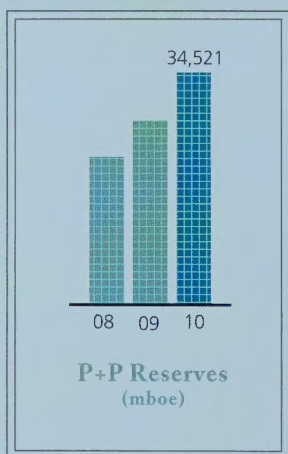
This is Delphi.

DELPHI ENERGY CORP. ANNUAL REPORT 2010

Fig. 1A - Summary

Delphi is a company that has real assets with real growth. We continue to expand in the Deep Basin of North West Alberta while developing the vast resources of our land. We operate approximately 93 percent of our production with ownership in strategic infrastructure resulting in robust operating netbacks per unit of production as well as an efficient finding and development cost structure.

The reality is that the natural gas market has changed. Delphi's tradition of operational excellence serves the Company well in successfully executing its business plan of delivering sustainable self-financed per share growth for years to come with in excess of 400 liquids-rich natural gas and light oil drilling locations in inventory.



Contents

2010 Highlights ... *1*
Message to the Shareholders ... *2*
Operational Review ... *6*
Operational Statistics ... *16*
Management Discussion & Analysis ... *22*
Management's Report ... *48*
Auditors' Report ... *49*
Consolidated Financial Statements ... *50*
Notes to Consolidated Financial Statements ... *53*
Corporate Information ... *67*

Fig. 1B - 2010 Highlights

Year Ended December 31	2010	2009
FINANCIAL HIGHLIGHTS		
($000's except per boe and per share amounts)		
Gross petroleum and natural gas sales	117,199	98,104
Per boe	39.71	39.50
Funds from operations	61,252	49,241
Per boe	20.75	19.81
Per share – Basic	0.57	0.59
– Diluted	0.57	0.59
Net earnings (loss)	(844)	(8,029)
Per boe	(0.29)	(3.23)
Per share – Basic	(0.01)	(0.10)
– Diluted	(0.01)	(0.10)
Capital invested	105,791	33,946
Dispositions of properties	(247)	(20,718)
Net capital invested	105,544	13,228
Acquisitions (1)	18	46,887
Total capital	105,562	60,115
Debt plus working capital deficit	108,054	92,538
Total assets	412,329	361,698
Shares outstanding (thousands)		
Basic	112,825	101,166
Diluted	120,601	108,594

(1) 2009 includes the costs of the acquisition of Fairmount Energy Inc.

Year Ended December 31	2010	2009
OPERATIONAL HIGHLIGHTS		
Average Daily Production		
Natural gas (mcf/d)	38,816	34,673
Percentage of total production	80%	85%
Oil and natural gas liquids (bbls/d)	1,617	1,029
Percentage of total production	20%	15%
Total (boe/d)	8,086	6,808
Realized selling prices		
Natural gas ($/mcf)	5.45	6.07
Oil ($/bbl)	76.63	63.87
Natural gas liquids ($/bbl)	53.66	48.50
Total oil equivalent ($/boe)	39.71	39.50
Wells drilled (net)	23.3	7.7
Undeveloped land		
Gross acres	424,819	372,896
Net acres	244,475	172,210
Average working interest (%)	58%	46%
Proved plus probable reserves (P+P)		
Natural gas (mmcf)	165,767	140,191
Oil and natural gas liquids (mbbls)	6,893	4,025
Total oil equivalent (mboe)	34,521	27,391
Finding and development costs (P+P)	14.24	14.25
Finding, development and acquisition (P+P)	14.91	9.21
Reserve life index (P+P)	11.7	11.0

Fig. 2 - Message to the Shareholders

~ *real* ~
dedication

David Reid
President and
Chief Executive Officer

2010 was an exceptional year for Delphi with the reported results generating a recurring theme of financial discipline and operational excellence in achieving our targets. Having doubled reserves and increased production by 52 percent over the past three years our rate of growth has been accelerating. Our growth strategies are being executed successfully and our vision of sustainable long term economic growth drives us on.

Production growth of 19 percent, cash flow growth of 24 percent and reserve growth of 26 percent are only a part of our successes in 2010. Operating margins are an integral part of our measure of success. In a low commodity price environment, these operating efficiencies are critical to maintaining sufficient cash generating capability to execute an economic growth plan. Delphi's cash generating capability on a per unit basis, excluding hedging gains, increased 47 percent in 2010 as a result of a significant increase in its crude oil and NGL production mix and material improvements in our cost structure. Costs have been reduced 25 percent over the past three years adding over $3.00 of cash flow to each barrel of oil equivalent ("boe") produced and in 2010 we produced 2.95 million boe. Those savings alone are enough to drill, complete, equip and tie-in three 100 percent wells at Wapiti/Gold Creek.

Natural gas prices averaged $4.00 per mcf in 2010, essentially flat to 2009 levels of $3.96 per mcf. Natural gas future price curves appear to have settled in to a range-bound trading pattern for the next several years representative of a perceived and persistant oversupply environment. We are assuming 2011 natural gas prices will be flat to 2010 levels with improvements looking into 2012. Delphi has maintained an active and successful hedging program despite lower price volatility, with the objective of protecting cash flow to execute a minimum level of capital spending. The Company's hedging program successfully contributed over $16.0 million to cash flow in 2010 or approximately $5.45 per boe to the cash netback. With lower natural gas price volatility looking forward, hedging becomes less about expectations for large hedging gains and more about simple downside price protection. We have hedged approximately 52 percent of our 2011 natural gas production at 4.93 per mcf, potentially generating gains of $6 million or increasing the cash netback by approximately $1.80 per boe.

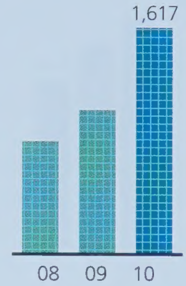
The successful growth of our cash generating capabilities through commodity mix change and cost structure improvements is, by design, displacing less predictable hedging gains as a material component of historically superior cash netbacks in a low natural gas price environment. Delphi achieved record reserve growth and top quartile finding and development ("F&D") costs as a result of a successful capital program in 2010, focused within its three core areas but spread over two light oil projects and multiple liquids-rich natural gas play-types. Economic results across multiple project types have significantly grown the Company's future drilling inventory. The inventory of liquids-rich natural

gas projects with F&D costs ranging from $6.00 to $12.00 and light oil projects with F&D costs averaging $20.00 per boe offer robust individual project economics and when blended deliver economic growth at targeted corporate recycle ratios. Over the past three years total reserves have doubled at an average F&D cost of $14.76 per boe.

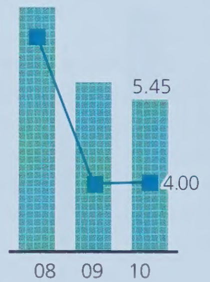
Our recycle ratio continues to be a reliable measure of economic growth defined by superior netbacks and top quartile finding and development costs. Delphi's three year recycle ratio average is 1.8 times.

The Company's fundamental principles within its growth strategies continue to provide a competitive advantage:

- Synergistic play-types within our Deep Basin core areas mitigate exploration and operational risks and drive down capital costs and maximize reserve additions.
- Large contiguous land positions complete with ownership in strategic infrastructure in each of our core areas provide repeatable and scalable project inventory with capital and production cost structure advantages.
- The robust revenue generating quality of the Company's NGL production stream and inventory of high liquids content growth opportunities is a natural hedge against natural gas price weakness while maintaining significant exposure to a recovery in natural gas prices.
- The Company maintains direct control over its core assets, operating over 93% of its production and 97% of its capital programs.
- An active hedging program maintains a forward-looking 12 to 24 month hedge position and provides protection for a defined level of capital spending.
- Financial stability and strength is maintained through prudent capital to cash flow, debt to cash flow and debt to equity ratios.



Liquids
(bbls/d)



Realized Gas Price
($/mcf)

AECO ($/mcf)

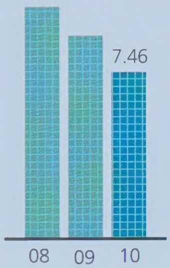
YEAR IN REVIEW

Financial results in 2010 are highlighted again by strong growth in funds flow from operations ("cash flow"). The AECO natural gas reference price averaged $4.00 per mcf in 2010 flat to $3.96 per mcf in 2009. The Company realized an average natural gas price of $5.45 per mcf in 2010 resulting from hedging gains of $16.1 million.

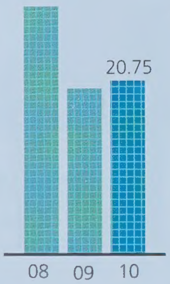
Cash flow increased 24 percent in 2010 to $61.3 million with hedging gains contributing 26 percent of the 2010 cash flow compared to 48 percent in 2009. Cash flow, excluding hedging gains, increased 75 percent as a result of a 19 percent increase in corporate production, a 58 percent increase in crude oil and NGL production and an 18 percent decrease in operating costs per boe.

Corporate cash netbacks, including hedging, increased five percent to $20.75 per boe compared to $19.81 per boe in 2009, while cash netbacks, excluding hedging gains, increased 47 percent or $5.00 per boe. Delphi views a $20.00 per boe cash netback target sustainable within the current natural gas price environment, without expectation of any hedging gains given the growth in liquids production and cost structure improvements.

Financial flexibility remained strong in 2010 with bank debt and working capital totalling 77 percent of available bank facilities at December 31, 2010. Unutilized credit available on the Company's $140.0 million banking facilities at the end of 2010 remained flat to 2009 levels at approximately $31.9 million while the debt to trailing cash flow ratio at December 31, 2010 improved to 1.8 times from 1.9 at December 31, 2009.



Operating Costs
($/boe)



Cash Flow Netbacks
($/boe)

Operational results in 2010, for the third year in a row are highlighted by record production volumes. Production during 2010 averaged 8,086 barrels of oil equivalent per day (boe/d), representing a 19 percent increase over 2009. Production during the fourth quarter of 2010 increased 24 percent to average a record 8,539 barrels of oil equivalent per day (boe/d) as compared to the fourth quarter in 2009. The Company also increased its crude oil and natural gas liquids production in the fourth quarter of 2010 by 84 percent to 2,053 barrels per day from 1,117 barrels per day during the fourth quarter of 2009. Crude oil and natural gas liquids production represented 24 percent of corporate production in the fourth quarter of 2010 compared to 16 percent during the comparative quarter of 2009.

During 2010, Delphi completed a net field capital program of $105.8 million with 88 percent of the capital directed at drilling, completions and equipping of new wells and production. The Company achieved 97 percent drilling success on a 36 (23.3 net) well program during 2010. The field capital program was expanded in the second half of the year upon completing an equity issue of $30.3 million at the end of the second quarter.

Delphi's total net land position, which is a measure of its future growth prospect inventory, including developed, under-developed and undeveloped lands has more than doubled over the past three years to 349,177 net acres (545 sections). Delphi's undeveloped land position grew 42 percent in 2010 to 244,475 net acres (382 sections). The Company has regulatory approval to drill up to four natural gas wells per pool per section on its lands at its three core properties of Bigstone, Hythe and Wapiti/Gold Creek.

Record reserve additions from the capital program replaced production in 2010 by 3.4 times, increasing the Company's reserve life index to 11.7 years. Proved producing reserves increased in 2010 by 14 percent, with total proved reserves and total proved plus probable reserves each increasing by 26 percent over 2009.

The Company has approximately 43 future development drilling locations booked in its year-end 2010 GLJ Engineering Report, representing approximately 18 months of drilling activity and requiring approximately $132 million of future capital. These 43 future locations are expected to generate proved and probable reserves of 11.3 million boe and 30 day initial production rates totaling 9,780 boe/d.

Delphi's total drilling inventory on its existing land base within its core areas of Hythe, Bigstone and Wapiti/Gold Creek is now estimated to exceed 400 locations. Delphi's land position in the Duvernay Shale totaling 50,848 net acres (79 sections) and 34,950 net acres (55 sections) in the Montney are also expected to contribute significant future drilling inventory as these emerging plays develop.

Finding, development and net acquisition cost ("FD&A") for 2010 on proved and probable reserve additions, inclusive of future development capital ("FDC") was $14.91 per boe. Operating netbacks were $24.34 per boe in 2010, generating a recycle ratio of 1.6 times.

The Company is well positioned to deliver long term sustainable growth in an environment of low natural gas prices. Our production mix yields a high quality revenue stream. The Company's low cost structure maximizes cash generating margins to re-invest into the significant inventory of drilling opportunities. Hythe, Wapiti/Gold Creek, and Bigstone in North West Alberta continue to deliver predictable economic production, reserves and cash flow growth. We believe the low-cost reserve additions achieved over the past three years are repeatable and scalable on our existing large

Management Team
Back row, left to right: Hugo Batteke, Michael Kaluza, Tony Angelidis, Rod Hume. Front row: Michael Galvin, David Reid, Brian Kohlhammer.

undeveloped and under-developed contiguous land bases within these core areas. Increased light oil and natural gas liquids production is providing a natural hedge against low natural gas prices.

OUTLOOK

2011 will be an exciting year for Delphi as we continue focusing on numerous liquids-rich natural gas development projects utilizing conventional vertical well techniques as well as horizontal drilling and multistage fracing techniques. We will also continue to direct capital to our light oil plays in both the Cardium and Doe Creek.

We expect to spend an estimated $70 to $80 million in 2011, drilling 30 gross wells (23 net) with significant field capital directed towards conventional vertical well opportunities in the "ultra" liquids-rich natural gas (up to 120 barrels per million cubic feet) core area of Wapiti/Gold Creek where up to 45 percent of the production is NGL's and F&D costs are under $8.00 per boe. Wells will also be drilled at Bigstone and Hythe core areas pursuing both light oil and liquids-rich natural gas. The first half 2011 capital program has a forecast crude oil and NGL production mix of approximately 55 percent. We anticipate that at least 85 percent of the capital will be focused on light oil and liquids-rich natural gas projects. The planned capital program is expected to result in average 2011 production volumes of 8,800 to 9,200 boe/d with a liquids weighting of approximately 27 percent.

We are forecasting continued low natural gas prices through 2011 due to the ample supply of natural gas in storage and continued high drilling rig count focused on the shale plays in the United States. Delphi is assuming 2011 AECO natural gas prices to average between Cdn $3.75 and $4.00 per mcf for budgeting purposes and has successfully mitigated downside commodity price risk with its natural gas hedging program. For 2011, the Company has again hedged approximately 52 percent of its natural gas production at an average floor price of $4.93 per mcf which represents a 36 percent premium to the March 15 , 2011 strip price of $3.63 per mcf.

Bank debt including working capital is estimated to be between $110 and $120 million at December 31, 2011.

We remain confident in our ability to maintain the momentum created over the past three years and to continue to deliver sustainable long term economic growth in this new paradigm of lower natural gas prices.

On behalf of the Board of Directors and all the employees of Delphi, we would like to thank our shareholders for their continued support as we strive to build upon the successes of 2010.

On behalf of the Board,

David Reid

David J. Reid
PRESIDENT AND CHIEF EXECUTIVE OFFICER
MARCH 16, 2011

Fig. 3 - Operational Review

~ real ~

assets

During 2010, Delphi continued to grow its land and infrastructure base, in the Deep Basin area of North West Alberta, with a goal of increasing the inventory of predictable, repeatable and scalable development opportunities that will provide years of economic growth. Delphi's Deep Basin assets can be characterized as having multi-zone potential with large in-place volumes of hydrocarbons that can be exploited with conventional vertical well techniques and horizontal drilling utilizing multi-stage fracturing techniques. The majority of Delphi's acreage lies within Development Entity No. 2, as defined by the Alberta Energy Resource Conservation Board, which allows for the drilling of up to four gas wells per pool per 640 acre spacing unit. The combination of multi-zone potential, large in-place volumes of hydrocarbons, high density drilling and the ability to commingle the various productive intervals encountered in the wellbore are major contributors to building a predictable, repeatable and scalable inventory of low risk, development opportunities. The Company incorporates the latest in drilling and completion techniques; specifically horizontal drilling, multi-stage fracturing and wellbore commingling to optimize productivity and increase ultimate reserve recovery. The oil and liquids-rich natural gas production generates a premium revenue stream which translates directly into higher field netbacks and increased cash flows. Finally, Delphi's ownership in the infrastructure, natural gas gathering systems and gas plants, that service the Company's extensive land base ensures our produced volumes will be gathered, processed and marketed in a manner that generates maximum cash flow.

$

Strong Cash Flow
Cash flow increased 24 percent in 2010 to $61.3 million as a result of increasing production volumes by 19 percent, increasing crude oil and NGL volumes by 58 percent and reducing operating costs per boe by 18 percent.

gas + ngl + oil

Strategy for Growth
Delphi has established a large continuous land position, in the Deep Basin of North West Alberta, that has multi-zone, oil and liquids-rich natural gas potential that can be exploited with conventional vertical well techniques and horizontal drilling utilizing multi-stage fracturing techniques.

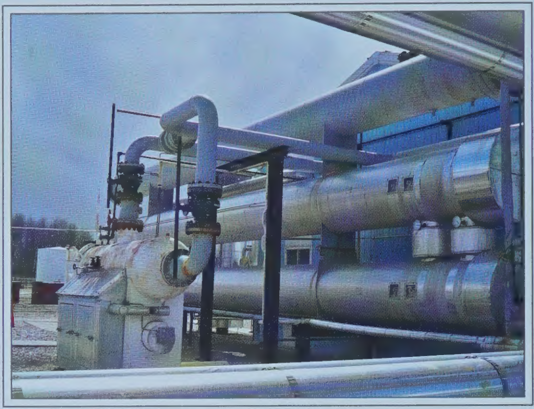
2:1

Delivering Growth
Delphi grew production to 8,086 boe/d in 2010, a 19 percent increase over 2009 volumes of 6,808 boe/d while growing oil and NGL volumes to 1,617 boed in 2010 from 1,029 in 2009.

	FROM 2010		TO 2011	
Liquids Volume	20 %	→	27 %	↑
Operating Costs	7.46 $/BOE	→	7.10 $/BOE	↓
Cash Costs	14.07 $/BOE	→	13.25 $/BOE	↓
Cash Netbacks	20.75 $/BOE	→	19.85 $/BOE	↓

In 2010, Delphi maintained its focus on value creation by generating strong field netbacks through a purposeful approach to increase revenue per boe and lower the corporate operating cost structure to offset the impact of lower hedging gains and continued low natural gas commodity prices.

The targeting of project capital to light oil and liquids-rich opportunities has resulted in Delphi's corporate liquid volumes increasing to 20 percent of total production in 2010, up 32 percent from 2009. This increase in liquid volumes has generated revenue per boe, excluding hedging gains, of $34.24 in 2010 which is up 14 percent from 2009. Ownership and control of the infrastructure servicing the Company's production has facilitated efforts to reduce operating costs across all operating areas resulting in 2010 operating costs of $7.46 per boe which is a reduction of 18 percent from 2009. The combination of increased revenue and decreased operating costs, on a per boe basis, has resulted in a 2010 field netback, prior to hedging gains, of $18.87 per boe, an increase of 29 percent over 2009 field netbacks. The ability to maintain strong field netbacks will be imperative to the Company's future growth and generation of solid operating and financial results during a period of low natural gas prices.



PRODUCTION

In 2010, Delphi's net production increased 19 percent to 8,086 boe/d from 6,808 boe/d in 2009. During the fourth quarter of 2010, net production increased 24 percent to 8,539 boe/d from 6,888 boe/d in the fourth quarter of 2009. Fourth quarter and full year production, in 2010 were 76 and 80 percent natural gas, respectively.

The Company's continued efforts to focus its resources in the Deep Basin area has been successful with approximately 7,065 boe/d or 83 percent of Delphi's 2010 fourth quarter volumes coming from the Bigstone, Hythe and Wapiti areas.

RESERVES

In 2010, Delphi increased total proved reserves by 26 percent to 22.7 million boe and total proved plus probable reserves by 26 percent to 34.5 million boe compared to 2009. Total proved plus probable reserves have doubled over the past three years. The Company added 10.1 million boe of total proved plus probable reserves (net of revisions and dispositions) in 2010, replacing 2010 production by 242 percent and achieved FD&A of $14.91 per boe. Over the last three years the Company's has achieved an average FD&A of $14.76 per boe for total proved plus probable reserves. Once again the continued focus on crude oil and natural gas liquids is evident in the 2010 reserve additions with total proved plus probable crude oil and natural gas liquids reserves increasing by 71 percent while total proved plus probable natural gas reserves increased by 18 percent compared to 2009. The Company's proved plus probable reserve life index ("RLI") increased to 11.7 years in 2010 compared to 11.0 years in 2009.

DRILLING

During the year ending December 31, 2010, the Company drilled 36 wells (23.3 net) resulting in 19 gas wells (13.5 net), 16 oil wells (9.5 net) and one dry hole (0.3 net) for an overall success rate of 97 percent. This drilling program consisted of 19 horizontal wells (12.5 net) and 17 vertical wells (10.8 net). In the fourth quarter of 2010, Delphi drilled four gas wells (2.3 net) and four oil wells (2.0 net).

Delphi continues to utilize vertical wells to develop the multi-zone potential of Deep Basin assets and where appropriate, horizontal wells with multistage fracture stimulations will target specific intervals to enhance productivity, reserve recovery and overall capital efficiencies. In many cases the horizontal wells will have completion opportunities in the vertical section of the wellbore, further leveraging the drilling capital and increasing capital efficiency.

PLAY TYPES

Delphi has focused on building a core area in the Deep Basin that positions the Company for economic growth in times of weak commodity pricing by targeting predictable, repeatable and scalable light oil and liquids rich-natural gas opportunities.

LIGHT OIL

The Company continues to develop light oil plays in the Doe Creek formation at Hythe and the Cardium formation at Bigstone with vertical and horizontal wells. In Hythe, at the end of 2010, the Company was producing Doe Creek oil from eight horizontal wells and through the winter program has plans to drill another four horizontal wells. Average rates after six months of production from the vertical wells ranged from 30 to 50 boe/d and the first eight horizontal wells averaged 340 boe/d during the first month of production. Current geologic mapping indicates the reservoir has the potential to extend over multiple sections of high working interest Delphi lands. Regionally there are numerous Doe Creek oil pools that have cumulative production ranging from 1.1 to 1.5 million barrels of oil and Delphi will be applying its knowledge base in search of additional Doe Creek pools along trend.

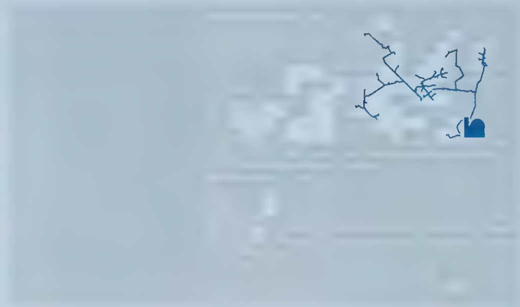
The second light oil play is the Cardium formation at Bigstone that has also been developed with vertical and horizontal wells. At year end, the Company was producing from nine vertical Cardium oil wells with individual well rates stabilizing at 30 to 80 boe/d after three months of production. Since early 2010, the Company has initiated production from five horizontal wells with average 30 day rates ranging from 129 to 460 boe/d with an average rate of 310 boe/d. Similar to the Doe Creek at Hythe, initial geologic mapping indicates the reservoir has the potential to extend over multiple sections of high working interest lands and the Company will continue to develop these lands as part of its effort to increase overall corporate liquids production.

LIQUIDS-RICH NATURAL GAS

In the Deep Basin, the Company is also pursuing multi-zone, liquids-rich natural gas in the Cretaceous interval (Doe Creek, Dunvegan, Paddy, Falher, Bluesky, Gething and Cadomin) and Jurassic interval (Nikanassin) utilizing vertical and horizontal wells. The ability to commingle multiple zones in a single wellbore allows the Company to maximize initial productivity and ultimate reserve recovery in a time frame that greatly enhances the well economics. Typically, three to six individual intervals are completed in a vertical well and subsequently produced as a commingled stream. Although many of the Company's targeted reservoirs generate attractive economic returns in vertical wells, there are additional reservoirs that are marginally economic as a result of lower productivity associated with tighter or laterally discontinuous reservoirs. Historically these reservoirs have been bypassed even though they contain significant quantities of hydrocarbons. Utilizing a combination of horizontal drilling, multi-stage fracturing and multi-zone commingling, these reservoirs are providing a low risk source of predictable, repeatable and scalable development opportunities.

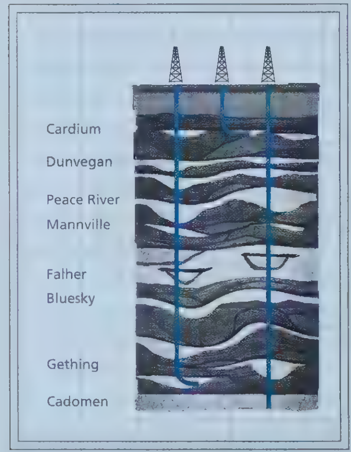
Delphi's goal is to apply the appropriate technologies that will result in an optimized development of the identified plays and continue to evaluate the application of these same technologies to new plays.

Bigstone



The Bigstone property is located 150 kilometres southeast of Grand Prairie and is the Company's second largest producing asset by volume, contributing 2,524 boe/d in 2010 of which 24 percent is crude oil and natural gas liquids. Delphi has an average working interest of 73 percent in 46,400 acres of land.

DELPHI FACILITIES — DELPHI GAS GATHERING SYSTEMS DELPHI LANDS



Since acquiring the Bigstone assets in 2005, the Company has drilled in excess of 60 wells with a 98 percent success rate and increased production by 250 percent.

In 2010, the Company accelerated development of the Cardium light oil play by drilling seven horizontal wells (3.2 net) and one vertical well (1.0 net) at a vertical depth of approximately 1,800 metres. The Cardium light oil play was initially developed with six vertical wells during 2006 and 2007 that had average initial production rates of 140 boe/d. The recent application of horizontal drilling with horizontal sections up to 1,350 metres and multi-stage completions with up to 16 fracture stimulations has resulted in initial average production rates of 310 boe/d per well and reserve recoveries twice that of the analog vertical wells.

In addition, the Company produces liquids-rich natural gas from up to seven productive horizons in the lower Cretaceous section from 1,900 to 2,800 metres. The multi-zone potential is a major factor in drilling success rates approaching 100 percent since acquiring the property in 2005. The sweet gas produced from these intervals has natural gas liquids content of approximately 30 barrels per million cubic feet of gas resulting in premium product pricing.

PRODUCTION / DRILLING

In 2010, average production decreased slightly to 2,525 boe/d from 2,600 boe/d in 2009. However, the light oil and natural gas liquids component increased to 610 boe/d in 2010 up 13 percent from 2009 as a result of a continuing emphasis on exploiting the Cardium light oil play. The increased liquids component resulted in the gross revenue per boe increasing to $38.50 in 2010 up 21 percent from $31.85 in 2009 resulting in cash flow per boe of $22.62 in 2010, a 44 percent increase from 2009 levels.

During the year ending December 31, 2010 the Company drilled eight oil wells (4.2 net) and four gas wells (1.9 net) resulting in a success rate of 100 percent.

FUTURE PLANS

In 2011, the Company will continue development of the Cardium light oil play with plans to drill up to six horizontal wells (2.7 net) offsetting the successful wells of the 2010 capital program. The Company is also licensing three horizontal wells targeting a liquids-rich natural gas target in the lower Cretaceous section for potential drilling in the second half of 2011. Increased productivity and ultimate reserve recoveries for the contemplated horizontal Cretaceous wells are anticipated to be similar to the increases observed in the Cardium play with initial production rates for a horizontal Cretaceous well ranging from 500 to 600 boe/d and an ultimate reserve recovery of 400,000 to 600,000 boe.

During 2010, the Company acquired a 100 percent working interest in mineral rights on 15,200 gross acres of land. The mineral rights are for a combination of shallow Cretaceous rights that the Company has been developing on offsetting lands and the deeper Montney and Duvernay shale that have been a focus of offset operator's recent activities in the area. The acquisition of these mineral rights is part of the Company's long term strategy of developing a predictable, repeatable and scalable inventory of development and resource style play types providing future growth opportunities. The timing of developing these lands will be dependent upon ongoing internal studies, offset industry success, commodity pricing and the economic merits of competing capital projects.

100%
drilling success rate

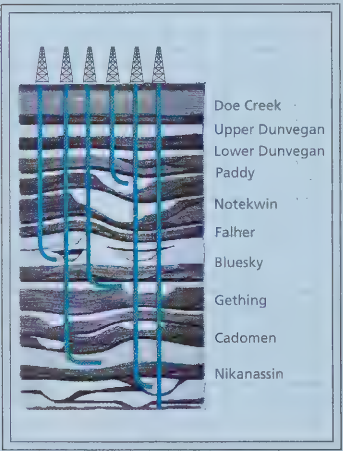
13%
increased light oil and NGL

44%
increased cash flow per boe

Hythe

The Hythe property is located 60 kilometres northwest of Grand Prairie and is the Company's largest producing asset by volume, contributing 3,160 boe/d in 2010; an eight fold increase from when the asset was acquired in September 2007. Delphi has an average working interest of 67 percent in 182,700 acres of land.

DELPHI FACILITIES — DELPHI GAS GATHERING SYSTEMS — DELPHI LANDS



Vertical well downspacing and horizontal well technology is creating a multi-year inventory of growth opportunities

Historically, Hythe has been developed utilizing one vertical gas well per 640 acre spacing unit with one or two zones completed during the initial stage of development. Subsequently, additional zones were accessed as the original completions depleted. A typical Hythe well will encounter up to eight productive horizons in the Cretaceous/Jurassic section from 1,000 to 2,400 metres with individual horizons having multiple productive zones. Once again the multi-zone nature of these assets has resulted in drilling success rates approaching 100 percent since acquiring the property.

Delphi acquired the property in 2007 and expanded upon this original development scheme by drilling additional vertical wells within the traditional spacing unit and completing up to nine zones during the initial completion operations. Current regulations allow for the drilling of up to four wells per section. These efforts were successful in growing production, increasing ultimate reserve recovery and identifying new development opportunities. During the 2009/2010 winter program the Company initiated a horizontal well program in combination with multi-stage fracture stimulations to enhance production rates, reserve recovery and capital efficiencies in Cretaceous intervals with significant gas in place volumes but moderate reserve recoveries. The horizontal well program has been a success with initial production rates exceeding 5 mmcf/d per well. The success of the multi-zone vertical well downspacing program and horizontal well program is creating a multi-year inventory of predictable, repeatable and scalable development opportunities. In addition to the natural gas opportunities at Hythe, Delphi has been active in developing a 2008 light oil pool discovery in the Doe Creek formation. After establishing Doe Creek light oil production in two vertical wells, the Company determined horizontal wells with multi-stage fracture stimulations would be the most efficient way to develop this pool. Through the end of 2010, Delphi has drilled seven horizontal oil wells (5.6 net) into the "GG" pool achieving an average 30 day rate of 270 boe/d per well. The Company has also initiated re-development of the Doe Creek Unit at Hythe with the drilling of two (0.8 net) horizontal oil wells and re-stimulation of several vertical wells. Although the Doe Creek Unit has been producing since 1987, the success encountered with horizontal

71%
increased production

52%
increased cash flow per boe

drilling and existing well re-stimulations indicates there are areas of low reserve recovery that will benefit from the application of the latest drilling and completion technologies.

PRODUCTION / DRILLING

In 2010, average production increased 71 percent to 3,160 boe/d from 1,850 boe/d in 2009. In addition, the light oil and natural gas liquids component increased to 610 boe/d in 2010 up threefold from 2009 levels as a result of the emphasis on exploiting the Doe Creek light oil play. The increased liquids component resulted in gross revenue per boe of $35.96 in 2010 up 17 percent from $30.73 in 2009 which in turn resulted in a cash flow per boe of $22.84, a 52 percent increase from 2009 levels.

During the year ending December 31, 2010 the Company drilled thirteen wells (10.2 net) resulting in seven horizontal oil wells (4.9 net), five horizontal gas wells (4.3 net) and one vertical gas well (1.0 net) for a success rate of 100 percent.

Production
(boe/d)

Since acquiring the Hythe assets in 2007, the Company has grown production from 400 to 3,160 boe/d in 2010, an eight fold increase.

FUTURE PLANS

In 2011, the Company will continue development of the Doe Creek light oil play with plans to drill up to seven horizontal oil wells (5.8 net) in the "GG" pool and Doe Creek unit. In addition, Delphi plans to drill up to four vertical, multi-zone natural gas wells (4.0 net) to confirm the resource nature of the Nikanassin and collect reservoir data that will aid in generating long term Cretaceous development plans and up to two horizontal wells (2.0 net) targeting natural gas in the Falher interval.

The Company has initiated a feasibility study to upgrade the NGL recovery process, on its owned processing facilities, with the intent of increasing the amount of liquids recovered to ratios similar to the much richer recoveries achieved at Bigstone.

Wapiti

The Wapiti assets are located south of Grand Prairie and include the producing areas of Chinook Ridge, Elmworth, Wapiti and Gold Creek. Production has increased 350 percent since the various producing areas were assembled in the second half of 2009. Delphi currently has an average working interest of 57 percent in 69,100 acres of land.

DELPHI FACILITIES — DELPHI GAS GATHERING SYSTEMS — DELPHI LANDS

The Wapiti assets are strategically located between the Company's Hythe and Bigstone core areas. Delphi has an ownership in an extensive natural gas infrastructure system including three natural gas processing plants with a combined through-put capacity of 720 million cubic feet per day, ten compressor stations and approximately 400 kilometers of gas gathering and transportation pipelines. The acquisition of these assets is an example of Delphi's strategy of acquiring multi-zone, liquids-rich natural gas with significant low risk development potential coupled with ownership in strategic infrastructure to support future growth. The properties are characterized by the same Cretaceous and Jurassic producing zones that Delphi is currently exploiting in Bigstone and Hythe.

A typical Wapiti/Gold Creek well will encounter up to seven productive horizons in the Cretaceous/Jurassic section from 800 to 3,100 metres. The sweet gas produced from these intervals is liquids-rich with condensate yields ranging from 20 to 120 barrels per million cubic feet of gas resulting in premium product pricing and enhanced project economics.

PRODUCTION / DRILLING

In 2010, average net production increased to 965 boe/d from 470 boe/d in 2009. An active 2010 drilling program resulted in fourth quarter production of 1,400 boe/d with the light oil and natural gas liquids accounting for 34 percent of the production stream.

During the year ending December 31, 2010 the Company drilled nine vertical gas wells (6.3 net), one oil well (0.3 net) and one dry hole (0.3 net) resulting in a success rate of 95 percent.

FUTURE PLANS

In 2011, the Company plans to drill up to 15 vertical gas wells (10.6 net) targeting the liquids-rich Triassic interval (Halfway and Charlie Lake), Jurassic interval (Nikanassin) and Cretaceous intervals (Gething, Bluesky, Falher, and Dunvegan). Approximately half of the Wapiti capital program will be directed towards drilling follow-up wells to successful multi-zone wells drilled during the 2010 capital program, therefore achieving low risk and capital efficient production increases. The remaining capital will be used to expand the drilling inventory by drilling extension wells targeting the same liquids-rich multi-zone targets.

New Ventures

Delphi has been acquiring mineral rights over two resource type plays since 2009 and currently has a 76 percent working interest in 45,700 acres in the Triassic Doig/Montney and an 81 percent working interest in 78,700 acres in the Devonian Duvernay.

DELPHI LANDS DELPHI LANDS WITH DUVERNAY AND/OR MONTNEY RIGHTS

The Company views these plays as being in the early stages of evaluation with the potential to provide future growth supplementing the existing development plays. The Company anticipates taking a staged approach to development activities after incorporating the results of geologic and engineering evaluations, competing organic projects, results of offsetting industry activities and commodity pricing.

The Montney rights are located at Bigstone, Hythe and Wapiti in North West Alberta and at Brassey in North East British Columbia. Montney development utilizing vertical and horizontal wells has been ongoing for several years to the east of Bigstone, in the Kaybob and Fir areas, with development activities moving steadily towards Bigstone. A recent horizontal Montney well was tested at 3.5 mmcf/d and 75 barrels of NGL's per mmcf gas within six kilometres of Delphi's Montney rights at Bigstone. Recent industry activity, in the Montney, has also been initiated to the north of Bigstone where an oil play is being developed at Waskahigan with test rates ranging from 1,000 to 1,400 boe/d and to the northwest of Bigstone where a liquids-rich natural gas play is being developed at Resthaven with test rates of 5.0 mmcf/d. The Company has a 94 percent working interest in 18,900 acres of Montney rights at Bigstone. At Hythe and Wapiti, Montney development has been accelerating with the development of the Sinclair field to the northwest of Hythe, the Elmworth field southwest of Hythe and north of Wapiti and the Karr field southwest of Wapiti. The Company has a 57 percent working interest in 16,000 acres of Montney rights at Hythe and Wapiti. At Brassey, offset operators are in the early stages of Montney/Doig development north, east and west of Delphi's land block. The Company has a 75 percent working interest in 10,800 acres of Montney and Doig rights at Brassey.

During 2010, Delphi established two separate land positions, through Crown land sales, in the Devonian Duvernay shale play. The Company has a 77 percent working interest in 66,700 acres at Sturgeon Lake and a 94 percent working interest in 12,000 acres at Bigstone. Initial geotechnical studies indicate the Duvernay shale should produce oil at Sturgeon Lake and liquids-rich natural gas at Bigstone. Limited production tests in the respective areas support the study results. A reasonable analog to the Duvernay shale would be Muskwa shale currently being developed in the Horn River Basin in North East British Columbia. To date, there has been limited drilling targeting the Duvernay shale in Alberta and the Company will be taking a measured approach to the development of these lands considering the capital cost of development and the current commodity price environment.

Fig. 4 - Operational Statistics

Operational Statistics

RESERVES

GLJ Petroleum Consultants Ltd. ("GLJ"), an independent petroleum engineering firm, has evaluated the crude oil, natural gas and natural gas liquids reserves of the Company as at December 31, 2010 and prepared a reserves report in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook. Full and complete disclosure information as required by NI 51-101 can be referenced in the Company's Annual Information Form ("AIF").

GLJ based its evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, operating cost data, capital budgets and future operating plans provided by the Company, information obtained from public records and GLJ's internal non-confidential files and commodity price forecast. The Reserves Committee, with the mandate of reviewing the independent engineering report, recommended the acceptance of the GLJ reserve estimates and it has been approved by the Board of Directors for the purposes of the Annual Report and AIF.

RESERVES RECONCILIATION

The reconciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2010 is as follows:

RECONCILIATION OF COMPANY INTEREST RESERVES [1][2][3]

	Light and Medium Crude Oil			Heavy Oil			Natural Gas Liquids			Total Gas[3]			MBOE (6:1)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mmcf)	(mboe)	(mboe)	(mboe)
December 31, 2009	834	470	1,304	246	135	381	1,321	1,020	2,341	93,701	46,490	140,191	18,018	9,373	27,391
Extensions and improved recovery	1,111	411	1,522	-	-	-	1,777	202	1,979	32,538	8,612	41,150	8,311	2,048	10,359
Technical revisions	185	(20)	165	24	4	27	24	172	196	(2,494)	2,851	357	(183)	632	449
Dispositions	(1)	(50)	(51)	(219)	(135)	(355)	(7)	(3)	(11)	(325)	(126)	(451)	(281)	(210)	(491)
Economic factors	2	1	3	(5)	(4)	(7)	(13)	-	(12)	(1,064)	(248)	(1,312)	(192)	(43)	(235)
Production	(300)	-	(300)	(46)	-	(46)	(243)	-	(243)	(14,168)	-	(14,168)	(2,952)	-	(2,952)
December 31, 2010	1,831	812	2,643	-	-	-	2,859	1,391	4,250	108,188	57,579	165,767	22,721	11,800	34,521

(1) Company interest reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.
(2) Company interest reserves are estimated using forecast prices and costs.
(3) The aggregate of associated and non-associated gas.

SUMMARY OF RESERVES

The following table outlines the oil, natural gas liquids and natural gas reserves of the Company by product type on a gross Company (before royalties and including Company royalty interest) basis. Both proved and proved plus probable reserves increased 26 percent as compared to year end 2009. Proved producing reserves account for 40 percent of the Company's total proved plus probable reserves.

Company Gross Reserves(1)(2)(3)	2010	2009	% change
Proved Developed Producing Reserves			
Light and medium crude oil (mbbls)	**1,089**	485	125
Heavy oil (mbbls)	-	219	(100)
Natural gas liquids (mbbls)	**1,431**	922	55
Natural gas excluding natural gas liquids (mmcf)	**68,544**	63,910	7
Total (mboe)	**13,944**	12,278	14
Proved Developed Non-Producing Reserves			
Light and medium crude oil (mbbls)	**156**	166	(6)
Heavy oil (mbbls)	-	26	(100)
Natural gas liquids (mbbls)	**507**	115	341
Natural gas excluding natural gas liquids (mmcf)	**13,161**	11,196	18
Total (mboe)	**2,857**	2,173	31
Proved Undeveloped Reserves			
Light and medium crude oil (mbbls)	**587**	183	221
Heavy oil (mbbls)	-	0	-
Natural gas liquids (mbbls)	**920**	284	224
Natural gas excluding natural gas liquids (mmcf)	**26,483**	18,595	42
Total (mboe)	**5,920**	3,567	66
Proved Reserves			
Light and medium crude oil (mbbls)	**1,831**	834	120
Heavy oil (mbbls)	-	246	(100)
Natural gas liquids (mbbls)	**2,859**	1,321	116
Natural gas excluding natural gas liquids (mmcf)	**108,188**	93,701	15
Total (mboe)	**22,721**	18,018	26
Probable Reserves			
Light and medium crude oil (mbbls)	**812**	470	73
Heavy oil (mbbls)	-	135	(100)
Natural gas liquids (mbbls)	**1,391**	1,020	36
Natural gas excluding natural gas liquids (mmcf)	**57,579**	46,490	24
Total (mboe)	**11,800**	9,373	26
Proved Plus Probable Reserves			
Light and medium crude oil (mbbls)	**2,643**	1,304	103
Heavy oil (mbbls)	-	381	(100)
Natural gas liquids (mbbls)	**4,250**	2,341	82
Natural gas excluding natural gas liquids (mmcf)	**165,767**	140,191	18
Total (mboe)	**34,521**	27,391	26

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company
(2) Gross reserves are estimated using forecast prices and costs
(3) Tables may not add due to rounding

FORECAST PRICES

The following table sets forth a summary of GLJ's January 1, 2011 escalated commodity price, currency exchange rate and inflation rate forecasts used in the preparation of the reserve estimates of the Company.

	West Texas Intermediate	Edmonton Light	AECO Spot	Exchange Rate	Inflation
	(US$/bbl)	(CDN$/bbl)	(CDN$/mmbtu)	(US$/CDN$)	(%)
2011	*88.00*	*86.22*	*4.16*	*0.980*	*2.0*
2012	*89.00*	*89.29*	*4.74*	*0.980*	*2.0*
2013	*90.00*	*90.92*	*5.31*	*0.980*	*2.0*
2014	*92.00*	*92.96*	*5.77*	*0.980*	*2.0*
2015	*95.17*	*96.19*	*6.22*	*0.980*	*2.0*
2016	*97.55*	*98.62*	*6.53*	*0.980*	*2.0*
2017	*100.26*	*101.39*	*6.76*	*0.980*	*2.0*
2018	*102.74*	*103.92*	*6.90*	*0.980*	*2.0*
2019	*105.45*	*106.68*	*7.06*	*0.980*	*2.0*
2020	*107.56*	*108.84*	*7.21*	*0.980*	*2.0*
Thereafter [1]	*+2.0%/yr*	*+2.0%/yr*	*+2.0%/yr*	*0.980*	*2.0*

(1) Percentage change of 2.00% represents the change in future prices each year after 2020 to the end of the reserve life.

The Company's realized sales prices for 2010, excluding hedging gains, were $4.33/mcf for natural gas and $75.81/bbl for crude oil.

NET PRESENT VALUE OF RESERVES – FORECAST PRICING [1][2]

The net present values of future net revenue of the Company's reserves at various discount rates before deducting future income tax expenses are outlined below.

	Discount Rate				
($000's)	0%	5%	10%	15%	20%
Proved developed producing reserves	*324,704*	*253,118*	*207,834*	*177,038*	*154,875*
Proved developed non-producing reserves	*68,852*	*44,872*	*32,957*	*25,942*	*21,321*
Proved undeveloped reserves	*121,867*	*74,876*	*48,808*	*32,861*	*22,362*
Proved reserves	***515,423***	***372,866***	***289,599***	***235,841***	***198,558***
Probable reserves	*318,641*	*173,926*	*109,855*	*75,933*	*55,696*
Proved plus probable reserves	***834,064***	***546,792***	***399,454***	***311,774***	***254,254***

(1) Before deducting future income tax expenses and reclamation costs
(2) The estimated net present values disclosed do not necessarily represent fair market value.

FINDING AND DEVELOPMENT COSTS

The Company has presented its finding and development costs for its exploration and development program in accordance with NI 51-101. The Company has also calculated other informative finding and development costs, including acquisitions and dispositions, and has summarized in the table below.

	2010		2009		2008 - 2010	
	Proved	**Proved plus Probable**	Proved	Proved plus Probable	Total Proved	Total Proved plus Probable
Capital Invested ($000's)						
Exploration and development (E&D) costs	**105,791**	**105,791**	33,946	33,946	216,516	216,516
Change in future development costs	**32,701**	**44,789**	4,622	12,284	68,272	97,088
Total development costs	**138,492**	**150,580**	38,568	46,230	284,788	313,604
Acquistion costs	**18**	**18**	46,887	46,887	85,025	85,025
Disposition proceeds	**(247)**	**(247)**	(20,718)	(20,718)	(29,415)	(29,415)
Total costs	**138,263**	**150,351**	64,737	72,399	340,398	369,214
Change in reserves (mboe)						
Reserve additions (1)	**7,936**	**10,573**	2,342	3,245	15,327	19,615
Aquisitions and dispositions	**(281)**	**(491)**	3,024	4,615	3,806	5,404
Total reserve additions	**7,655**	**10,082**	5,366	7,860	19,133	25,019
Finding and Development Costs ($/boe)						
Exploration and development, excluding change in FDC	**$ 13.33**	**$ 10.01**	$ 14.49	$ 10.46	$ 14.13	$ 11.04
Exploration and development, including change in FDC	**$ 17.45**	**$ 14.24**	$ 16.47	$ 14.25	$ 18.58	$ 15.99
Exploration, development, acquisitions and dispositions, including change in FDC(2)	**$ 18.06**	**$ 14.91**	$ 12.06	$ 9.21	$ 17.79	$ 14.76

(1) Includes extensions and improved recovery, technical revisions, discoveries, and economic factors.

(2) Includes all extensions and improved recovery, technical revisions, discoveries, economics factors, acquisitions, and dispositions and the total costs (which include the total year over year change in total future development costs).

(3) The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.

(4) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

RESERVE LIFE INDEX

The reserve life index of Delphi has been calculated by dividing year end 2010 reserves by the average 2010 annual production of 8,086 boe/d. The reserve life index is 11.7 years on a proved plus probable basis.

	Crude Oil and NGL(mbbls)			Natural Gas (mmcf)			Mboe (6:1)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Reserves - Dec. 31, 2010	4,690	2,203	6,893	108,188	57,579	165,767	22,721	11,800	34,521
Production	590		590	14,168		14,168	2,952		2,952
Reserves life index (years)	**7.9**		**11.7**	**7.6**		**11.7**	**7.7**		**11.7**

RESERVES PER OUTSTANDING COMMON SHARE

The proved plus probable reserves per 1,000 common shares of the Company at December 31, 2010 was 306.0 compared to 270.8 the previous year; an increase of 13 percent.

	2010	2009
December 31 Proved plus probable reserves (mboe)	**34,521**	27,391
Year end common shares	**112,825,298**	101,166,132
Proved plus probable boe reserves per 1,000 outstanding common shares	**306.0**	270.8

PRODUCTION PER OUTSTANDING COMMON SHARE

2010 average daily production per 1,000,000 common shares of the Company at December 31, 2010 was 71.7 compared to 67.3 the previous year; an increase of six percent.

	2010	2009
Production (boe/d)	**8,086**	6,808
Year end common shares	**112,825,298**	101,166,132
Production per 1,000,000 Shares	**71.7**	67.3

ACREAGE SUMMARY

The Company's total and undeveloped landholdings by province as at December 31, 2010 are outlined below.

	Total		Undeveloped		Fair Market
December 31, 2010 (acres)	Gross	Net	Gross	Net	Value (1)
Alberta	508,430	293,746	313,472	205,540	$19,094,827
British Columbia	168,750	55,431	111,347	38,935	$ 8,555,222
Total	677,180	349,177	424,819	244,475	$27,650,049

(1) Undeveloped land value of $27,650,049 at December 31, 2010 based on Seaton-Jordan & Associates Ltd. land valuation report.

RECYCLE RATIO

Recycle ratio is an indicator of the effectiveness of the Company's re-investment program. Recycle ratio is a key measure in the oil and gas industry of capital efficiency and profitability and is calculated by dividing the Company's operating netback by the finding and development costs for total capital invested.(1)

Year ended December 31	**2010**	2009	2008
Operating netback ($/boe)(1)	**24.35**	24.10	33.83
Proved plus probable reserves F&D costs ($/boe)(2)	**14.91**	9.21	20.70
Proved plus probable recycle ratio	**1.63**	2.62	1.63

(1) *Operating netback is calculated by subtracting royalties, operating costs, and transportation costs from revenues and dividing by production.*
(2) *Includes extensions and improved recovery, technical revisions, discoveries, economic factors, acquisitions and disposition and total costs (which include changes in future development costs).*

RESERVE REPLACEMENT

Reserve replacement ratio is calculated by dividing reserve additions by total production.

	Proved	Proved + Probable
Total reserve additions (mboe)(1)	7,655	10,082
Production (mboe)	2,952	2,952
Total reserve replacement ratio	**2.59**	**3.42**

(1) *Includes extensions and improved recovery, technical revisions, discoveries, economic factors, acquisitions and dispositions.*

NET ASSET VALUE

The net asset value of the Company at December 31, 2010, using the net present value of future net revenue discounted at a rate of ten percent before deducting future income tax expenses, is summarized below.

($000's except per share value)	
Estimated future net revenues of proved plus probable reserves (1)	399,454
Undeveloped land (2)	27,650
Mark-to-market value of hedging contracts	650
In-the-money option proceeds (3)	9,248
Total asset value	**437,002**
Bank debt plus working capital deficiency	(108,054)
Net asset value	**328,948**
Common shares outstanding and in-the-money options	119,632,109
Net asset value per share	**2.75**

(1) *Discounted at 10 percent and before deducting future income tax expenses and reclamation costs.*
(2) *Undeveloped land value was determined by an independent land valuation report by Seaton-Jordan & Associates Ltd.*
(3) *In-the-money option proceeds are based on the closing December 31, 2010 share price of $2.17.*
(4) *The Company estimates it has approximately $270 million of tax deductions available to offset future taxable income.*

Management Discussion and Analysis

(ALL TABULAR AMOUNTS ARE STATED IN THOUSANDS OF DOLLARS, EXCEPT PER UNIT AMOUNTS)

Management's discussion and analysis ("MD&A") has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp. ("Delphi" or "the Company"). The discussion and analysis is a review of the financial condition and results of operations of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and twelve months ended December 31, 2010 and 2009 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2010 and 2009. The discussion and analysis has been prepared as of March 15, 2011.

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.

The MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", "cash operating costs" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain/(loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The Company has defined net debt as the sum of long term debt plus/minus working capital excluding the current portion of future income taxes and risk management asset/liability. Net debt is used by management to monitor remaining availability under its credit facilities. Cash operating costs have been defined as the sum of operating expenses, transportation expenses, general and administrative expenses and interest costs.

DELPHI'S OPERATIONS

WHAT IS THE NATURE OF DELPHI'S BUSINESS AND WHERE ARE ITS OPERATIONS?

Delphi Energy Corp. is a publicly-traded company, listed on the Toronto Stock Exchange, engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are principally concentrated in the Deep Basin of North West Alberta which represents 90 percent of its production in 2010. The Company has four primary core areas in the Deep Basin located at Bigstone, Hythe, Wapiti/Gold Creek and Tower Creek.

2010 ACCOMPLISHMENTS

WHAT WERE THE HIGHLIGHTS OF DELPHI'S OPERATIONS IN 2010?

Canadian natural gas prices continued to be challenging in 2010, increasing only one percent from 2009, which was the lowest average price in the last ten years. Delphi focused its exploitation efforts in its core areas in the Deep Basin of North West Alberta and in particular on its strategic acquisitions from 2009, with vertical and horizontal drilling operations emphasizing light oil and liquids-rich natural gas opportunities. Hence, despite a marginal increase in natural gas prices, the Company's operations resulted in another successful year towards growing long-term value for its shareholders.

In 2010, the Company achieved numerous accomplishments as follows:

- achieved record average production with volumes of 8,086 barrels of oil equivalent per day ("boe/d"), an increase of 19 percent compared to 2009;
- changed the production mix to approximately 24 percent crude oil and natural gas liquids in the fourth quarter of 2010, up from 16 percent in the fourth quarter of 2009, which contributed to higher operating and cash flow netbacks;
- generated funds from operations ("cash flow") of $61.3 million, an increase of 25 percent from the previous year;
- increased the cash flow netback by five percent to $20.75 per boe compared to $19.81 in 2009;
- increased cash flow per share, excluding hedging gains, by 57 percent compared to 2009;
- reduced operating costs by 18 percent to $7.46 per boe in 2010 from $9.08 per boe in the previous year;
- realized $16.1 million in hedging gains on commodity contracts;
- increased total proved reserves by 26 percent to 22.7 million boe and increased total proved plus probable reserves by 26 percent to 34.5 million boe;
- increased yearly average production per share by six percent and increased year-end reserves per share by 13 percent;
- drilled 36 (23.3 net) wells with an overall success rate of 97 percent;
- achieved average finding, development, acquisitions and dispositions costs of $18.06 per proved boe and $14.91 per proved plus probable boe;
- generated a recycle ratio of 1.6 times on an operating netback of $24.34 per boe;
- issued 11.0 million common shares for gross proceeds of $30.3 million;
- increased the Company's credit facilities from $125.0 million to $140.0 million throughout the year providing $31.9 million of available credit and a twelve month trailing net debt to funds from operations ratio of 1.8:1 at December 31, 2010;
- reduced net debt per boe at December 31, 2010 on a proved and proved plus probable basis for the fourth year in a row to $4.76 and $3.13 per boe, respectively; and
- increased the Company's total undeveloped land holdings by 42 percent to 244,475 net acres as compared to December 31, 2009, at an average acquisition cost in 2010 of approximately $72.00 per acre.

Cash flow for 2010 was $61.3 million or $0.57 per basic share, compared to $49.2 million or $0.59 per basic share in 2009. The growth in cash flow in 2010 over 2009 was primarily a result of the continued reduction in operating costs, change in production mix towards higher netback crude oil and natural gas liquids production and the continued benefit of the Company's risk management program.

Operating costs before processing income were $0.9 million lower than the previous year despite average production growth of 19 percent in 2010 compared to 2009. The fixed costs associated with owned natural gas plant infrastructure, field compression facilities and pipelines continue to be allocated over more production volumes resulting in lower marginal costs of new production. The Company continues to focus production growth in its core areas where operating costs in 2010 were less than $6.00 per boe on a weighted average basis. The Company's operating costs were reduced by $1.62 to $7.46 per boe in 2010, 18 percent lower than the previous year.

Light crude oil prices traded at an average 18 times the price of natural gas in 2010 and the Company's natural gas liquids traded at an average of 12 times the price of natural gas. Consequently, there existed a significant difference in realized netbacks between crude oil and natural gas liquids versus natural gas production. To maintain a cash

netback of at least $20.00 per boe, the Company increased its capital focus on light oil and liquids-rich natural gas opportunities in 2010. As a result of this effort, Delphi was able to increase its liquids production mix throughout the year resulting in a fourth quarter of 2010 liquids ratio of 24 percent of production versus 16 percent in the fourth quarter of 2009. The increased liquids production contributed to achieving a cash netback of $20.75 per boe in 2010.

For the year ended December 31, 2010, the Company recognized $16.1 million in realized gains on financial and physical hedging contracts providing significant stability to the Company's cash flow. The Company realized 98 percent of these gains on approximately 19.3 million cubic feet per day of natural gas hedged at an average floor price of $6.27 per mcf with the remaining $0.3 million due to hedging gains on crude oil contracts in 2010.

On June 3, 2010, the Company closed an equity offering of 11.0 million common shares at $2.75 per share for gross proceeds of approximately $30.3 million (net proceeds of $28.3 million). The net proceeds were initially used to reduce the Company's net debt and subsequently funded an expanded capital program in the second half of 2010.

The combination of the above highlighted items resulted in Delphi's financial position continuing to remain strong at the end of 2010, providing the financial flexibility to execute its 2011 capital program. At December 31, 2010, the Company had net debt of $108.1 million on total credit facilities of $140.0 million, providing excess financial capacity of approximately $31.9 million. On a 12 month trailing funds from operations basis, Delphi's net debt to cash flow ratio was 1.8:1 and on a net debt to annualized fourth quarter funds from operations basis it was 1.5:1. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes.

FINANCIAL STRATEGIES

ARE THERE FINANCIAL STRATEGIES THE COMPANY EMPLOYS TO ACHIEVE RESULTS AND FORECAST EXPECTATIONS?

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in cash flow resulting from fluctuating commodity prices. Delphi's program involves executing numerous forward sales contracts over a period of time to take advantage of the volatility in the natural gas and light crude oil market. The strategy takes advantage of the swings in prices as a result of a) the changes in demand/supply fundamentals and/or b) the movement of significant financial assets invested in the market as a pure commodity play. The transactions are generally undertaken for contract terms 12 to 24 months in advance with financially strong counterparties and are predominantly executed on a physical basis with the Company's natural gas marketer. Delphi's risk management program consists of fixed price contracts, costless collars, participating swaps and puts and calls which provide downside protection. Costless collars, participating swaps and puts also provide the opportunity to share in the upside if market prices increase above the floor price. If market prices are above fixed price contracts or the ceiling price of costless collars and calls, the Company would continue to achieve its downside protection while realizing losses on these hedging contracts. Delphi has a strategy of hedging approximately 40 to 50 percent of its production as long as demand/supply fundamentals indicate volatile markets in the future.

Delphi continues to direct efforts at maintaining or reducing its controllable costs. Increasing production at its operating fields which are processed through Company owned infrastructure reduces facility fixed costs on a per boe basis and improves netbacks. Field operators are encouraged to undertake preventative maintenance on field infrastructure and wellsite equipment to minimize production downtime and prevent significant operating costs associated with major repairs. The Company strives to achieve improvement in its costs of production and at a minimum maintain current production costs while growing production.

Maintaining or improving strong operating netbacks per boe through the risk management program and the control of costs associated with production operations and corporate overhead, allows the Company to pursue its planned capital program with greater confidence that financial flexibility will be maintained while incurring capital expenditures to grow production volumes. The risk management program has been and will continue to be an integral part of maximizing operating netbacks during periods of price volatility and excess natural gas supply.

As a result of the significant difference in netbacks between crude oil and natural gas, the Company's capital expenditures have been allocated more towards light oil and liquids-rich natural gas opportunities. By altering the Company's production mix, there is greater certainty of achieving the Company's cash flow expectations due to the higher netback crude oil and natural gas liquids production.

The annual net capital expenditure program in the field will continue to approximate forecast cash flow. Additional capital may be approved as a result of opportunistic acquisitions, incremental cash flow from greater than expected production growth, higher than forecast cash netbacks or other sources of financing.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing cash flow growth resulting in a lower net debt to funds from operations ratio. The Company continues to be focused on achieving its internal target range for this ratio of 1.3 to 1.5 times. In a low price environment, the Company's objective would be to reduce or at least not increase the net debt balance by undertaking a capital program within cash flow.

2011 OUTLOOK AND FORWARD-LOOKING INFORMATION

This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", may", "will", "should", believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this management discussion and analysis contains forward-looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Additional information on these and other factors that could affect the Company's operations or financial results are included in reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). The forward-looking statements and information contained in this MD&A are made as of March 15, 2011 for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Delphi undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Delphi's operational and financial expectations for 2011 are based upon the Company's projection of drilling plans, drilling success and production results and the estimated related revenues and associated costs of royalties, transportation expenses, operating costs, general and administrative expenses and interest costs. Commodity prices used in the determination of forecast revenues are based upon general economic conditions, commodity supply and demand forecasts and publicly available price forecasts. The Company continually monitors its forecast assumptions to ensure the stakeholders are informed of material variances from previously communicated expectations.

OPERATIONS

HOW MANY WELLS DOES DELPHI EXPECT TO DRILL IN 2011?

Delphi expects to drill 30 gross wells (23 net) in 2011 focussed in its core areas of Bigstone, Hythe and Wapiti/Gold Creek. In Bigstone and Hythe, drilling will primarily be horizontal wells directed at light oil opportunities in the Cardium formation and Doe Creek formation, respectively. At Wapiti/Gold Creek, the drilling will primarily be directed at vertical multi-zone opportunities with the liquids-rich Nikinassin formation being the primary target. The factors that may hinder Delphi from achieving its drilling plans include the availability of drilling rigs and equipment needed at the drill site, timely receipt of well licenses and permits and approval by the landowners for surface access to the location.

WHAT ARE THE COMPANY'S PRODUCTION EXPECTATIONS?

Delphi expects production from crude oil, natural gas and natural gas liquids to average between 8,800 to 9,200 boe/d in 2011, up 11 percent from 2010. The production mix is expected to be approximately 27 percent light oil and liquids-rich natural gas in 2011, compared to 20 percent in 2010, as the capital program focuses on light oil and liquids-rich natural gas drilling opportunities. These production and sales mix expectations may not be achieved if decline rates are greater than expected, the new wells do not perform as expected, drilling plans are delayed for the reasons outlined above, completion and tie-in of new wells is delayed due to weather or the unavailability of the required service equipment in the field, mechanical failure of field equipment, delays in accessing production facilities or additional waiting time for any approvals.

REVENUES

WHAT DOES THE COMPANY PROJECT FOR CRUDE OIL AND NATURAL GAS PRICES IN 2011?

NATURAL GAS

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system (AECO). Natural gas prices are primarily influenced by North American, rather than global, supplies of natural gas versus domestic demand for winter heating and summer cooling requirements. However, with the growth in natural gas liquefaction and regasification facilities around the world this North American supply and demand balance is subject to disruption from time to time, primarily in periods of a shortfall in supply. In addition, multi-stage fracturing technology has unlocked the significant natural gas resource potential of numerous shale basins in North America capable of initially producing at very high rates of natural gas.

For forecasting purposes, Delphi continues to expect a challenging natural gas market for 2011 as a result of the high rig count in the United States directed at horizontal drilling using multi-stage fracturing technology into the shale gas plays. The Company has prepared its 2011 expectations based on an average AECO price of $4.00 per million cubic feet.

CRUDE OIL

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the Canadian/United States ("Cdn/US") dollar exchange rate. The fundamental supply/demand equation for crude oil is more balanced on a daily basis than natural gas due to consistent demand for crude oil of approximately 88 million barrels per day to meet the global requirement for energy. The price of crude oil can also be influenced significantly by geopolitical events in the major oil exporting countries of the world and the strength or weakness of the global economies.

Delphi anticipates WTI to average U.S. $85.00 per barrel in 2011, based on a balanced equation of supply and demand fundamentals supporting strengthening world economies.

CANADIAN/UNITED STATES EXCHANGE RATE

Both crude oil and natural gas prices in Canada are premised on the U.S. dollar price for each product adjusted for the Cdn/US dollar exchange rate and quality and transportation differentials. The strength or weakness of the Canadian dollar versus the U.S. dollar will largely reflect the global demand for raw materials, particularly metals, minerals and crude oil. The global financial markets tolerance for risk and its need for financial security in the form of holding U.S dollars will also have an effect on the value of the Canadian dollar against the U.S. dollar. Delphi believes the Canadian dollar will remain quite strong relative to the U.S. dollar in 2011 as global economies recover from the slowdown since 2008.

The Canadian dollar is expected, on average, to trade at parity with the U.S. dollar in 2011. The exchange rate is influenced by many variables which will continue to result in significant volatility.

HAS DELPHI UNDERTAKEN ANY HEDGES FOR 2011 TO MITIGATE THE RISK OF VOLATILITY IN ITS PRODUCT PRICING?

In light of the low natural gas prices over the past two years and a future outlook which has resulted in the forward price curve for natural gas to decrease based on the view that there is more than an ample supply of natural gas with the development of the shale gas plays, particularly in the United States, Delphi has become more focused on protecting the downside of prices as opposed to locking in gains to be made on unusually high prices. Currently, Delphi has hedged approximately 52 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $4.93 per mcf for 2011. This compares to the forward strip commodity price for AECO of $3.52 per mcf for the remainder of 2011 as of February 25, 2010. Delphi continually monitors the variables affecting the price of natural gas and crude oil in order to ensure its capital program is in line with expected funds from operations. The following natural gas hedges are in place to support the Company's cash flow.

	Jan-Mar 2011	Apr-Sep 2011	Oct-Dec 2011	Total 2011
Production hedged (mmcf/d)	16.1	23.5	17.2	20.1
Percentage of natural gas production*	41%	60%	44%	52%
Price floor (Cdn $/mcf)	$5.24	$4.77	$4.90	4.93

* *based on 39 mmcf/d*

The Company also has executed a call option at U.S. $90.00 on 600 bbls/d of oil for January 1, 2011 to December 31, 2012. The fair value of outstanding natural gas contracts is estimated to be a gain of approximately $5.2 million with a loss of approximately $6.8 million on outstanding crude oil contracts as of February 25, 2010.

ROYALTIES

WHAT AVERAGE ROYALTY RATE DOES DELPHI EXPECT TO PAY IN 2011?

The Company pays royalties to provincial governments, individuals and companies that own mineral rights. These payments take the form of Crown, freehold and overriding royalties. Crown royalty rates for crude oil and natural gas are generally calculated on a sliding scale based on commodity prices and production rates whereas freehold and overriding royalty rates are generally a fixed percentage of revenue. Crown royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to minimum and maximum rates. For natural gas liquids, Crown royalty rates are a fixed percentage of revenue with the rate varying according to the nature of the product. Crown royalty credits are received from the Crown and represent the fee earned by the owners of natural gas processing infrastructure to process the Crown's royalty share of natural gas. Freehold royalties are paid on freehold lands and overriding royalties are generally payable on lands where the Company has earned an interest in the lands through a farm-in, whether the lands are Crown or freehold. Royalties are not affected by gains or losses realized through the Company's risk management program.

For 2011, Delphi expects its royalty rate, after the deduction for royalty credits, will average between 15 to 17 percent of gross revenue, excluding realized and unrealized gains or losses from its risk management program.

TRANSPORTATION EXPENSES AND OPERATING COSTS

WILL DELPHI BE ABLE TO FURTHER REDUCE ITS COSTS OF PRODUCTION IN 2011?

Transportation expenses are costs incurred by the Company to transport its production volumes from the wellhead to the point of sales. In British Columbia, infrastructure is owned by Spectra Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Delphi expects its transportation expenses to be approximately $2.75 per boe in 2011. Transportation expenses are subject to the availability of pipeline capacity on an interruptible basis in areas of significant production growth by industry.

Operating costs have been trending downward over the past several years as Delphi focuses its capital program and achieves growth in its core areas of Bigstone, Hythe and Wapiti/Gold Creek, all areas with an operating cost structure of less than $6.00 per boe As production grows and fixed area costs are allocated over increased production volumes, the marginal cost of the incremental production is expected to be less than field average operating cost. In 2011, Delphi will also realize the full year benefit of the 2010 disposition of very high operating cost production in East Central Alberta.

The costs of production may be more than expected in periods of very high industry activity causing considerable competition and rising prices for general oilfield services and equipment. Further reductions in operating costs are anticipated in 2011, down to an estimated $7.10 per boe.

GENERAL & ADMINISTRATIVE AND INTEREST COSTS

WHAT ARE THE COMPANY'S OVERHEAD COSTS FOR PERSONNEL AND FINANCING?

Delphi believes it is adequately staffed to grow the Company's production to in excess of 12,000 boe/d. In 2011, Delphi anticipates its general and administrative costs, net of capitalized amounts, to be approximately $1.80 per boe. A high level of industry activity may cause an increase in general and administrative expenses due to higher than expected employee costs to retain employees or to hire new employees and general cost inflation.

Interest costs will be dependent on market rates and credit spreads for the oil and gas sector and will be a function of the general economic conditions in Canada. If the economy is viewed as growing too fast, which may result in inflation, interest rates may be increased to slow down the pace of growth in the economy. Interest costs may also increase if cash flow from operations is less than expected and bank debt is used to fund a larger portion of the capital program than originally anticipated. Interest expense is expected to be $1.60 per boe in 2011.

CAPITAL PROGRAM AND NET DEBT LEVELS

WHAT ARE THE COMPANY'S FORECAST CAPITAL EXPENDITURES AND NET DEBT LEVELS FOR 2011?

In 2011, Delphi anticipates a field capital program between $70.0 and $80.0 million resulting in net debt levels between $110.0 and $120.0 million by the end of 2011. Growth in cash flow to approximately $65.0 million is expected to result in a net debt to cash flow ratio of approximately 1.8:1 at the end of 2011.

As in prior years, net debt is expected to increase in the first quarter of 2011 as a result of a winter capital program greater than cash flow with net debt being reduced in the second quarter as capital expenditures are expected to be minimal due to spring breakup. The significant excess cash flow generated in the second quarter will be applied against net debt. Capital expenditures for the second half of the year will be planned according to the cash flow generated and achieving net debt targets.

2010 OPERATIONAL AND FINANCIAL RESULTS

BUSINESS ENVIRONMENT

WHAT EXTERNAL FACTORS OF THE BUSINESS ENVIRONMENT DID THE COMPANY HAVE TO CONTEND WITH IN 2010?

The price the Company receives for its production volumes is a significant determinant of the Company's cash flow. The table below outlines the changes in the various benchmark commodity prices and economic parameters which affect the prices received for the Company's production.

BENCHMARK PRICES AND ECONOMIC PARAMETERS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
NATURAL GAS						
NYMEX (US $/mmbtu)	**3.81**	4.19	(9)	**4.38**	3.90	12
AECO (CDN $/mcf)	**3.64**	4.49	(19)	**4.00**	3.96	1
CRUDE OIL						
West Texas Intermediate (US $/bbl)	**85.17**	76.17	12	**79.55**	61.93	28
Edmonton Light (CDN $/bbl)	**80.32**	76.54	5	**77.48**	66.02	17
FOREIGN EXCHANGE						
Canadian to U.S. dollar	**1.01**	1.06	(4)	**1.03**	1.14	(10)
U.S. to Canadian dollar	**0.99**	0.95	4	**0.97**	0.88	10

NATURAL GAS

In January, 2010, the AECO price for natural gas was range bound between Cdn. $5.25 and $5.75 per mcf in anticipation of normal withdrawals of natural gas from storage to meet winter heating demand. In late January, however, natural gas prices began to decrease and continued to do so through the remainder of the quarter as natural gas drilling activity was increasing and the primary geographical areas for natural gas demand during the winter heating season began experiencing above average temperatures. In addition, U.S. industrial demand continued to be reduced due to the economic slowdown.

In the second quarter of 2010, natural gas prices followed the cyclical trend, decreasing further as winter heating demand ended and natural gas production was placed into storage to meet the upcoming winter's heating demand.

Throughout the summer months, natural gas prices continued declining as summer cooling demand for natural gas was more than offset by domestic natural gas production in the United States with excess production being placed into storage to meet the coming winter's heating demand. Industrial demand was recovering but not at a rate significant enough to alleviate the ample supply of natural gas which continued to adversely affect the view of supply and demand fundamentals putting additional downward pressure on natural gas prices in the short to medium term.

In the fourth quarter of 2010, Cdn. natural gas prices rebounded from the lows of approximately $3.15 per mcf to $4.20 per mcf in anticipation of winter weather for the coming months. With more than adequate natural gas in storage to meet heating demand requirements, Cdn. prices in the fourth quarter were $0.85 per mcf lower than the fourth quarter of 2009.

The overall drop in natural gas prices for the year had a significant effect on the active drilling rig count in both Canada and the United States but this reduced rig count has not had a significant effect on U.S. natural gas supply and hence storage levels in the United States. Natural gas production failed to decrease in a manner consistent with historical declines associated with reduced drilling activity. Reduced overall drilling for natural gas was more than offset by drilling horizontally into initially higher productivity non-conventional formations, particularly shale gas.

AECO gas prices hit a low of $3.12 per mcf in October of 2010 but only recovered to over $4.00 per mcf by the end of the year. AECO averaged $4.00 per mcf in 2010, one percent higher than the previous year.

CRUDE OIL

Through the first three quarters of 2010, the price for crude oil averaged between U.S. $75.00 and U.S. $80.00 per barrel as the global demand for oil continued to stabilize around the world. The U.S. based price for crude oil was affected by several factors over that time period including the decline in the value of the U.S. dollar compared to the currency of most of its major trading partners and the global demand for oil due to concerns over the global economic recovery in light of government deficits throughout parts of Europe.

In the fourth quarter of 2010, the price of crude oil averaged U.S. $85.17 per barrel as the economies of the developing countries continued to grow at an even stronger pace and the concerns over the European deficit crisis, while not resolved, subsided as the issues were being addressed. WTI averaged U.S. $79.55 per barrel in 2010, an increase of 28 percent over the previous year.

CANADIAN/UNITED STATES EXCHANGE RATE

In 2010, the general trend for the value of the Canadian dollar against its U.S. counterpart was that of a stronger Canadian dollar. As a producer of crude oil, a stronger Canadian dollar has a negative effect on the price received for production. The exchange rate volatility was affected by the financial markets demand for the United States dollar as a safe haven in these uncertain economic times. The Cdn/US exchange rate varied from a high of $1.08 early in 2010 to a low of $0.99 later in the year. This negative effect to the price of oil for Canadian producers was compounded by a widening basis differential between U.S. and Canadian markets. In 2010, Canadian crude oil prices averaged $77.48 per barrel compared to $66.02 per barrel in 2009, a 17 percent increase over the previous year.

INDUSTRY COST OF SERVICES

Drilling contractors and oilfield service companies became very busy due to the high crude oil prices and the demand to drill horizontal oil and natural gas wells using multi-stage fracturing technology. Natural gas drilling focused on liquids-rich natural gas opportunities and high deliverability natural gas wells in the Canadian shale gas plays, predominantly the Montney formation. In the latter half of 2010, the high crude prices and horizontal drilling activity resulted in pricing pressure on drilling equipment capable of completing these types of operations. Completion services also tightened up as more and more horizontal drilling was undertaken with the intention of completing the wells using multi-stage fracturing technology.

DRILLING OPERATIONS

HOW ACTIVE WAS DELPHI IN ITS DRILLING PROGRAM IN 2010 AND WHERE WAS THE DRILLING FOCUSED?

The Company had another successful year in 2010 drilling 36 gross (23.3 net) wells with a success rate of 97 percent. The drilling was primarily focused on the core properties of Bigstone, Hythe and Wapiti/Gold Creek in North West Alberta. In light of decreasing natural gas prices experienced after the first quarter of 2010, the Company focused its efforts on drilling light oil and liquids-rich natural gas opportunities for the remainder of the year.

	Three Months Ended December 31		Twelve Months Ended December 31	
	Gross	*Net*	*Gross*	*Net*
Natural gas wells	4.0	2.3	19.0	13.5
Oil wells	4.0	2.0	16.0	9.5
Dry holes	-	-	1.0	0.3
Total	8.0	4.3	36.0	23.3
Success rate (%)	100	100	97	99

CAPITAL INVESTED

HOW MUCH DID THE COMPANY SPEND IN 2010 AND WHERE WERE THE CAPITAL EXPENDITURES INCURRED?

The Company continued to direct its capital program at its core areas in North West Alberta to take advantage of the multi-zone nature of these assets, low production operating costs and quick on-stream capability associated with owned gathering and processing infrastructure. Total capital invested in the field was $105.8 million, net of drilling credits of $5.9 million, with approximately 78 percent directed at drilling and completion operations and 11 percent incurred on equipping and facility projects. Approximately $3.7 million of the capital incurred in the fourth quarter related to the start of the 2011 winter drilling program.

In prior years, Delphi generally acquired its undeveloped land as part of its asset acquisition strategy. In 2010, the Company has been more active at Crown land sales, acquiring undeveloped land in the Deep Basin of North West Alberta, primarily focused in its core areas of Bigstone, Hythe and Wapiti/Gold Creek. In 2010, Delphi acquired 50,566 net acres in these areas. Delphi also added to its growth potential with the acquisition of 50,848 net acres of Duvernay shale rights at an attractive entry cost targeting light oil. Delphi's inventory of undeveloped land has increased to approximately 244,475 net acres, up 42 percent from December 31, 2009. In 2010, the Company spent $7.3 million on land, primarily at Crown land sales.

During the second quarter, the Company disposed of its non-core properties in East Central Alberta for $0.3 million. The properties consisted of medium quality oil and natural gas production with operating costs in excess of $30.00 per boe. With the disposition, the Company benefits from a reduction in total operating costs per boe and the reduction of asset retirement obligations associated with the properties of approximately $1.9 million.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	*2009*	*% Change*	**2010**	*2009*	*% Change*
Land	**1,173**	(155)	-	**7,316**	828	784
Seismic	**116**	(11)	-	**462**	369	25
Drilling and completions	**17,228**	5,803	197	**82,062**	21,327	285
Equipping and facilities	**(985)**	1,198	-	**11,281**	6,789	66
Capitalized overhead	**1,468**	1,579	(7)	**4,480**	4,202	7
Other	**(686)**	28	-	**190**	431	(56)
Capital invested	**18,314**	8,442	117	**105,791**	33,946	212
Disposition of properties	**-**	(10,765)	100	**(247)**	(20,718)	(99)
Net capital invested	**18,314**	(2,323)	-	**105,544**	13,228	698
Acquisition of properties	**(369)**	11,422	-	**18**	30,873	(100)
Acquisition of Fairmount Energy Inc.	**-**	16,014	(100)	**-**	16,014	(100)
Total capital invested	**17,945**	25,113	(29)	**105,562**	60,115	76

PRODUCTION

WHAT FACTORS CONTRIBUTED TO THE 19 PERCENT GROWTH IN PRODUCTION VOLUMES AND THE SUCCESS IN GROWING OIL AND NATURAL GAS LIQUIDS VOLUMES?

Production for the twelve months ended December 31, 2010 averaged 8,086 boe/d representing an increase of 19 percent over the comparative period due to the successful drilling and optimization programs at Bigstone, Hythe and Wapiti/Gold Creek. With the weakness in natural gas pricing, Delphi's 2010 drilling program targeted opportunities in its crude oil and liquids-rich natural gas inventory to maximize netbacks. For the twelve months ended December 31, 2010, production growth is highlighted by a 57 percent increase in crude oil and natural gas liquids compared to 2009. A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material growth opportunities in existing and new play concepts.

The Company's production for the year was weighted 80 percent to natural gas, 12 percent to crude oil and eight percent to natural gas liquids.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	*2009*	*% Change*	***2010***	*2009*	*% Change*
Natural gas (mcf/d)	***38,918***	*34,626*	*12*	***38,816***	*34,673*	*12*
Crude oil (bbls/d)	***1,147***	*630*	*82*	***950***	*525*	*81*
Natural gas liquids (bbls/d)	***906***	*487*	*86*	***667***	*504*	*32*
Total (boe/d)	***8,539***	*6,888*	*24*	***8,086***	*6,808*	*19*

Crude oil production was 81 percent higher than the previous year. The increase in oil production is due to the successful horizontal drilling targeting Cardium light oil at Bigstone and the Doe Creek light oil at Hythe.

Natural gas liquids production was 32 percent higher for the year primarily due to the increased natural gas liquids in the Wapiti/Gold Creek area where the Company has been successfully drilling multi-zone vertical wells with the Nikanassin formation as the primary target.

REALIZED SALES PRICES

WHAT WERE THE SALES PRICES REALIZED BY THE COMPANY FOR EACH OF ITS PRODUCTS?

For the three and twelve months ended December 31, 2010, Delphi's risk management program realized a gain of $4.0 million and $16.1 million, respectively. For the quarter, the realized gain was $1.13 per mcf with physical contracts contributing a gain of $0.92 per mcf and financial contracts contributing a gain of $0.21 per mcf. For the twelve months ended December 31, 2010, the average realized natural gas price was ten percent less than the comparative period due to a decrease in hedge gains offset by higher heat content and marketing arrangements on natural gas volumes.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	*2009*	*% Change*	***2010***	*2009*	*% Change*
AECO ($/mcf)	***3.64***	*4.49*	*(19)*	***4.00***	*3.96*	*1*
Heating content and marketing ($/mcf)	***0.23***	*0.25*	*(9)*	***0.33***	*0.26*	*27*
Gain on physical contracts ($/mcf)	***0.92***	*1.32*	*(30)*	***0.90***	*1.57*	*(43)*
Gain on financial contracts ($/mcf)	***0.21***	*0.09*	*130*	***0.22***	*0.28*	*(21)*
Realized natural gas price ($/mcf)	***5.00***	*6.15*	*(19)*	***5.45***	*6.07*	*(10)*
Edmonton Light ($/bbl)	***80.32***	*76.54*	*5*	***77.48***	*66.02*	*17*
Gain (loss) on financial contracts ($/bbl)	***(0.56)***	-	-	***0.82***	-	-
Quality differencial ($/bbl)	***(3.18)***	*(2.41)*	*32*	***(1.67)***	*(2.15)*	*(22)*
Realized oil price ($/bbl)	***76.58***	*74.13*	*3*	***76.63***	*63.87*	*20*
Realized natural gas liquids price ($/bbl)	***51.43***	*53.02*	*(3)*	***53.66***	*48.50*	*11*
Total realized sales price ($/boe)	***38.79***	*41.50*	*(7)*	***39.71***	*39.50*	*1*

Delphi's oil production has changed from a mix of light and medium oil to predominantly light oil therefore the Company's average price for crude oil, since mid 2010, will generally fluctuate with the change in the benchmark crude oil prices. With the disposition of the East Central Alberta properties in the second quarter of 2010, increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in

pricing more reflective of light oil. The Company's realized crude oil and natural gas liquids prices were significantly higher than the comparative year as a result of the increase in benchmark prices, the reduction in quality differential and gains on risk management contracts.

HOW DO THE REALIZED NATURAL GAS PRICES COMPARE TO THE BENCHMARK AECO PRICING?

Excluding hedges, the Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of its natural gas production and the sale of approximately 5.5 million British thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index.

The following table outlines the premium Delphi realized on its natural gas price compared to the average quarterly AECO price due to the risk management program, quality of production and gas marketing arrangements. In years of both high and low commodity price environments, Delphi's realized sales price has been a premium to AECO.

	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31
	2010	*2010*	*2010*	*2010*	*2009*	*2009*	*2009*	*2009*
Natural Gas Price								
Delphi realized ($/mcf)	**5.00**	5.28	5.30	6.26	6.15	5.77	5.81	6.55
AECO average ($/mcf)	**3.64**	3.54	3.89	4.96	4.49	2.94	3.47	4.95
Premium to AECO	**37%**	49%	36%	26%	37%	96%	67%	32%
Hedging gain ($000's)	**4,045**	4,676	4,186	2,941	4,498	7,973	6,997	3,991

RISK MANAGEMENT ACTIVITIES

WHAT IS DELPHI'S RISK MANAGEMENT STRATEGY AND WHAT CONTRACTS ARE IN PLACE TO MITIGATE THE RISK OF VOLATILITY?

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile. For natural gas production, Delphi has hedged approximately 52 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $4.93 per mcf for 2011.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of operations. Physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. Due to this derivative, the changes in the fair value of these contracts are included in the statement of earnings.

The Company has fixed the price applicable to future production through the following contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2010 – March 2011	*Natural Gas*	*Physical*	*1,500 GJ/d*	*$5.74 fixed*
January 2010 – March 2011	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$5.72 fixed*
April 2010 – March 2011	*Natural Gas*	*Physical*	*3,000 GJ/d*	*$6.12 fixed*
April 2010 – March 2011	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$5.73 fixed*
January 2011 – December 2011	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$3.79 fixed*
January 2011 – December 2011*	*Natural Gas*	*Financial*	*2,500 GJ/d*	*$7.14 Call*
January 2011 – December 2011***	*Natural Gas*	*Financial*	*3,000 GJ/d*	*$4.00 Put*
January 2011 – December 2011****	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$4.12 fixed*
January 2011 – December 2012**	*Crude Oil*	*Financial*	*600 bbls/d*	*U.S. $90.00 Call*
April 2011 – October 2011	*Natural Gas*	*Physical*	*2,000 GJ/d*	*$5.66 fixed*
April 2011 – October 2011	*Natural Gas*	*Physical*	*4,000 GJ/d*	*$3.80 fixed*
April 2011 – October 2011	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$3.82 fixed*
April 2011 – October 2011	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$3.79 fixed*
April 2011 – December 2011**	*Natural Gas*	*Financial*	*6,810 GJ/d*	*$5.69 fixed*
January 2012 – December 2012***	*Natural Gas*	*Financial*	*3,000 GJ/d*	*$4.50 Call*
January 2012 – December 2012****	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$4.50 Call*

* *The Company had a natural gas put contract at $4.75 per gigajoule on 2,500 gigajoules per day for the period April 1, 2010 through October 31, 2010. This put was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $7.14 per gigajoule for the period January 1, 2011 through December 31, 2011.*

** *The Company has acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. This contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012.*

*** *The Company has acquired a natural gas put contract at $4.00 per gigajoule on 3,000 gigajoules per day for the period January 1, 2011 through December 31, 2011. This put was paid for with the sale of a natural gas call on 3,000 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.*

**** *The Company has acquired a natural gas contract at $4.12 per gigajoule on 2,500 gigajoules per day for the period January 1, 2011 through December 31, 2011. This contract was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.*

The Company recognized an unrealized loss on its financial contracts of $1.1 million in 2010. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company accounts for its Canadian dollar physical sales contracts, which were entered into and continue to be held for the purpose of delivery of production, in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

REVENUE

HOW DO REVENUES IN 2010 COMPARE TO 2009 AND WHAT FACTORS CONTRIBUTED TO THE CHANGE?

For the three and twelve months ended December 31, 2010, Delphi generated revenue of $30.5 million and $117.2 million, respectively, representing an increase of 16 percent and 19 percent over the comparative periods. The increase in revenue is a result of an increase in production volumes. Contributing to the increased price per boe is the increase in production of crude oil and natural gas liquids.

The risk management program associated with natural gas and crude oil pricing generated revenue of $16.1 million in 2010. For nine consecutive quarters, Delphi has received a significant premium to AECO pricing primarily due to the success of the risk management program.

WHAT IS THE BREAKDOWN OF REVENUES BY PRODUCT AND THE OVERALL CONTRIBUTION TO REVENUE OF THE RISK MANAGEMENT PROGRAM?

Delphi is predominantly a natural gas producer due to the nature and location of its assets. Hence 52 percent of the Company's revenue for the year was from natural gas sales at market prices, crude oil represented 22 percent and natural gas liquids contributed 11 percent. The risk management program associated with natural gas and crude oil pricing generated revenue of $16.1 million in 2010 or 14 percent of total revenues.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Natural gas	**13,848**	15,093	(8)	**61,352**	53,363	15
Natural gas physical contract gains	**3,303**	4,218	(22)	**12,705**	19,913	(36)
Crude oil	**8,140**	4,239	92	**26,287**	12,238	115
Natural gas liquids	**4,287**	2,376	80	**13,063**	8,922	46
Sulphur	**214**	91	135	**365**	182	101
Realized gain on risk management contracts	**683**	280	144	**3,427**	3,546	(3)
Total	**30,475**	26,297	16	**117,199**	98,164	19

ROYALTIES

WHAT WERE ROYALTY COSTS IN 2010?

In 2010, the Company paid Crown, freehold and gross overriding royalties. Crown royalties of $15.8 million were partially offset by $5.9 million of royalty credits for processing the Crown's share of natural gas with the net amount of $9.9 million representing 69 percent of the total royalties paid in 2010 compared to 76 percent in 2009. The net Crown royalties increased in 2010 compared to 2009 primarily as a result of higher oil prices in 2010 and the Company's significant increase in crude oil and natural gas liquids production.

Freehold royalties were $0.2 million in 2010 compared to $0.4 million in 2009. Freehold royalties represent one percent of the total royalties paid versus four percent in 2009 and are much lower than the previous year due to the disposition of the properties in East Central Alberta in the second quarter of 2010.

Gross overriding royalties represented 30 percent of total royalties in 2010 compared to 20 percent in 2009. The increase in gross overriding royalties to $4.4 million in 2010 compared to $1.8 million in 2009 is primarily a result of the five percent gross overriding royalty granted on the Bigstone property late in 2009 as well as various farm-in transactions undertaken by the Company.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Crown royalties	**3,416**	3,316	3	**15,843**	14,134	12
Royalty credits	**(1,589)**	(1,863)	(15)	**(5,963)**	(7,337)	(19)
Crown royalties – net	**1,827**	1,453	26	**9,880**	6,797	45
Freehold royalties	**(3)**	91	-	**167**	361	(54)
Gross overriding royalties	**1,070**	1,016	5	**4,373**	1,824	140
Total	**2,894**	2,560	13	**14,420**	8,982	61
Per boe	**3.68**	4.04	(9)	**4.89**	3.61	35

WHAT WERE THE AVERAGE ROYALTY RATES PAID ON PRODUCTION IN 2010?

The average royalty rates were not significantly different than the previous year. Crown royalty rates were virtually unchanged as a result of a minimal change in benchmark natural gas prices from year to year. Overriding royalties increased primarily as a result of the overriding royalty granted late in 2009.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Crown rate – net of royalty credits	**6.9%**	6.7%	3	**9.8%**	9.1%	7
Gross overriding rate	**4.0%**	4.7%	(13)	**4.3%**	2.4%	77
Average rate	**10.9%**	11.7%	(7)	**14.3%**	12.0%	19

The royalty rate calculations above exclude gains or losses on risk management activities from revenue as the denominator.

OPERATING EXPENSES

HOW HAS THE COMPANY BEEN ABLE TO REDUCE ITS OPERATING EXPENSES IN 2010 AS COMPARED TO 2009?

Operating costs on a per boe basis for the twelve months ended December 31, 2010, decreased 18 percent over the comparative year. The decrease is attributed to lower field operating costs as well as increased volumes from the cost efficient core areas of Hythe, Wapiti/Gold Creek and Bigstone. The Company accumulated new and additional infrastructure in its core areas during 2009 which will allow for lower per boe operating costs as production volumes continue to increase. Additionally, the disposition of the East Central Alberta properties in the second quarter of 2010 provided a decrease in absolute costs. Operating costs in the fourth quarter of 2010 were $5.88 per boe which represents a 13 percent decrease over the $6.76 per boe experienced in 2009. The fourth quarter reduction can be attributed to increased operating efficiencies as well as favorable prior period adjustments for natural gas plant equalizations which decreased operating costs by $1.25 per boe in the fourth quarter. Excluding the favorable prior period adjustments, Delphi's corporate operating costs in the fourth quarter were $7.12 per boe.

The Company earns processing income on third party production volumes going through facilities owned by Delphi. The processing income represents a reduction of the Company's costs to operate these facilities and hence is deducted in determining operating expenses. Processing income indicates the Company has excess capacity at its facilities which it can access to handle growth in its production volumes.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Production costs	**5,351**	4,856	10	**24,558**	25,443	(3)
Processing income	**(735)**	(571)	29	**(2,545)**	(2,892)	(12)
Total	**4,616**	4,285	8	**22,013**	22,551	(2)
Per boe	**5.88**	6.76	(13)	**7.46**	9.08	(18)

TRANSPORTATION EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Total	**2,089**	1,499	39	**8,908**	6,739	32
Per boe	**2.66**	2.37	12	**3.02**	2.71	11

WHAT FACTORS CONTRIBUTED TO THE INCREASE IN TRANSPORTATION COSTS IN 2010?

On a per boe basis, transportation costs for the three and twelve months ended December 31, 2010, increased by 12 percent and 11 percent, respectively, over the comparative periods. The increase in transportation costs is attributed to additional transportation capacity acquired in the latter half of 2009 which will be utilized as production volumes grow in core areas and the increased cost associated with trucking the Company's growth in crude oil volumes.

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
General and administrative costs	**3,721**	4,475	(17)	**12,191**	12,123	1
Overhead recoveries	**(497)**	(261)	90	**(1,940)**	(888)	118
Salary allocations	**(1,636)**	(2,033)	(20)	**(4,720)**	(5,447)	(13)
Total	**1,588**	2,181	(27)	**5,531**	5,788	(4)
Per boe	**2.02**	3.44	(41)	**1.87**	2.33	(20)

HOW DO GENERAL AND ADMINISTRATIVE COSTS IN 2010 COMPARE TO 2009?

On a per boe basis, general and administrative costs for the twelve months ended December 31, 2010 decreased 20 percent over the comparative period in 2009 due to an increase in production volumes. Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal.

STOCK-BASED COMPENSATION

WHAT IS STOCK-BASED COMPENSATION EXPENSE?

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Stock-based compensation	**325**	301	8	**1,457**	1,467	(1)
Capitalized costs	**(130)**	(161)	(19)	**(467)**	(852)	(45)
Total	**195**	140	39	**990**	615	61
Per boe	**0.25**	0.22	13	**0.34**	0.25	34

The stock-based non-cash compensation expense for the three and twelve months ended December 31, 2010, increased 13 percent and 34 percent, respectively, over the comparative period. The increase in 2010 is attributed to additional stock options granted to new employees. During the three and twelve months ended December 31, 2010, Delphi capitalized $0.1 million and $0.5 million, respectively, of stock-based compensation associated with exploration and development activities.

INTEREST

HOW DO THE COSTS OF BORROWING COMPARE AGAINST THE PRIOR YEAR?

For the three and twelve months ended December 31, 2010, interest expense on a per boe basis decreased 32 percent and 12 percent over the comparative periods. The decrease in 2010 is attributed to the increase in production volumes.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Total	**1,301**	1,555	(16)	**5,075**	4,863	4
Per boe	**1.66**	2.45	(32)	**1.72**	1 96	(12)

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. At December 31, 2010, the bankers' acceptances have terms ranging from 90 to 182 days and a weighted average effective interest rate of 4.24 percent over the term.

WHAT HAS THE COMPANY DONE TO PROTECT ITSELF AGAINST AN INCREASE IN INTEREST RATES?

The Company has entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $40.0 million maturing on May 4, 2011. The bankers' acceptance rate on the transaction will increase in fixed monthly increments of 4.55 basis points for an average fixed rate over two years of 0.94 percent. The effective interest rate over the two year term on $40.0 million of bankers' acceptances will be 0.94 percent plus the applicable stamping fee. The interest rate swap is fair valued at each reporting date and presented in the risk management asset or liability.

DEPLETION, DEPRECIATION AND ACCRETION

HAS THE COMPANY'S DEPLETION AND DEPRECIATION RATE AND EXPENSE CHANGED IN 2010 AS COMPARED TO 2009?

Depletion and depreciation per boe for the three and twelve months ended December 31, 2010 decreased four and 13 percent over the comparative periods. With continued drilling success at Bigstone, Hythe and Wapiti/Gold Creek, Delphi has been able to add proved reserves at a cost below the Company's current depletion rate. The increase in total depletion and depreciation was a result of increased production volumes as the average depletion rate for 2010 was lower than the previous year.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	*2009*	*% Change*	**2010**	*2009*	*% Change*
Depletion and depreciation	**15,648**	*13,271*	*18*	**59,732**	*57,906*	*3*
Accretion expense	**232**	*219*	*6*	**955**	*818*	*17*
Total	**15,880**	*13,490*	*18*	**60,687**	*58,724*	*3*
Depletion and depreciation per boe	**19.92**	*20.94*	*(5)*	**20.24**	*23.30*	*(13)*
Accretion per boe	**0.29**	*0.35*	*(15)*	**0.32**	*0.33*	*(2)*
Total per boe	**20.21**	*21.29*	*(5)*	**20.56**	*23.63*	*(13)*

WHAT IS ACCRETION EXPENSE AND HOW DID THIS EXPENSE FOR 2010 COMPARE TO 2009?

The accretion of asset retirement obligations is an expense that relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit adjusted risk-free interest rate of eight to ten percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense per boe for the three and twelve months ended December 31, 2010 decreased 15 percent and two percent respectively, over the comparative periods.

INCOME TAXES

WHAT WAS THE AFFECT ON FUTURE INCOME TAXES AS A RESULT OF THE LOSS IN THE YEAR?

The provision for future income taxes in the financial statements for the three and twelve months ended December 31, 2010 was a recovery of $0.6 million. Delphi does not anticipate it will be cash taxable before 2014.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Current	-	-	-	-	-	-
Future (reduction)	**(640)**	(1,031)	(38)	**(647)**	(4,171)	(84)
Total	**(640)**	(1,031)	(38)	**(647)**	(4,171)	(84)
Per boe	**(0.81)**	(1.63)	(50)	**(0.22)**	(1.68)	(87)

FUNDS FROM OPERATIONS

WHAT ARE FUNDS FROM OPERATIONS AND WHY IS IT A KEY PERFORMANCE MEASURE?

Funds from operations is a non-GAAP measure that has been defined by the Company as net earnings (loss) plus the add back of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain (loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations. Delphi uses funds from operations ("cash flow") to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments to grow the Company's value for the shareholders and to repay debt.

HOW DO FUNDS FROM OPERATIONS IN 2010 COMPARE TO 2009?

For the three and twelve months ended December 31, 2010, funds from operations were $18.0 million ($0.16 per basic share) and $61.3 million ($0.57 per basic share) compared to $14.2 million ($0.14 per basic share) and $49.2 million ($0.59 per basic share) in the comparative periods. The increase in funds from operations is a result of an increase in production volumes and a reduction in operating costs, interest expense and general and administrative expenses per boe.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	2009	% Change	**2010**	2009	% Change
Net earnings (loss)	**(204)**	1,386	(85)	**(844)**	(8,029)	(89)
Non-cash items:						
Depletion, depreciation and accretion	**15,880**	13,490	18	**60,687**	58,724	3
Unrealized loss on risk management activities	**2,348**	233	908	**1,066**	2,102	(49)
Stock-based compensation expense	**195**	140	39	**990**	615	61
Future income tax reduction	**(640)**	(1,030)	(38)	**(647)**	(4,171)	(84)
Funds from operations	**17,987**	14,218	27	**61,252**	49,241	24

HOW DO FUNDS FROM OPERATIONS COMPARE TO CASH FLOW FROM OPERATING ACTIVITIES IN THE FINANCIAL STATEMENTS?

Funds from operations reflect two primary differences from the GAAP term "cash flow from operating activities" shown on the financial statements. These differences are expenditures incurred for asset retirement obligations and changes in non-cash operating working capital. The following table is a reconciliation of funds from operations to cash flow from operating activities for the three and twelve months ended December 31, 2010 and 2009.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	*2009*	*% Change*	***2010***	*2009*	*% Change*
Funds from operations: Non-GAAP	**17,987**	14,218	27	**61,252**	49,241	24
Expenditures on asset retirement obligations	**(265)**	(167)	59	**(265)**	(167)	59
Change in non-cash working capital	**819**	(688)	-	**(2,154)**	(4,142)	(48)
Cash flow from operating activities: GAAP	**18,541**	13,363	39	**58,833**	44,932	31

NET EARNINGS

WHAT FACTORS CONTRIBUTED TO THE LOSS IN 2010?

For the three and twelve months ended December 31, 2010, Delphi recorded net earnings of $0.2 million ($nil per basic share) and a net earnings loss of $0.8 million ($0.01 per basic share), respectively. Net earnings were affected by non-cash items such as depletion, depreciation and accretion, unrealized gains on risk management activities, stock-based compensation and future income taxes. These non-cash items represent the majority of the significant difference between funds from operations and net earnings.

NETBACK ANALYSIS

HOW DO DELPHI'S NETBACKS ACHIEVED IN 2010 COMPARE TO THE PRIOR YEAR?

For 2010, the Company's netbacks were higher than the previous year resulting from a slightly higher realized sales price and significant operating cost, G&A and interest cost reductions. The Company strives for an operating netback in the $22.00 to $25.00 per boe range and a cash netback of $20.00 per boe in the current commodity price environment. The operating netback and cash netback were higher than the cost of finding and developing reserves resulting in a positive recycle ratio.

Delphi's production is predominantly natural gas and therefore Delphi's operating and cash netbacks are primarily driven by the price received for natural gas. The Company is focused on increasing its light oil and natural gas liquids percentage of total production volumes to further strengthen its cash flow netback per boe.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2010	*2009*	*% Change*	**2010**	*2009*	*% Change*
BARRELS OF OIL EQUIVALENT ($/BOE)						
Realized sales price	**38.79**	41.50	(7)	**39.71**	39.50	1
Royalties	**3.68**	4.04	(9)	**4.89**	3.61	35
Operating expenses	**5.88**	6.76	(13)	**7.46**	9.08	(18)
Transportation	**2.66**	2.37	12	**3.02**	2.71	11
OPERATING NETBACK	**26.57**	28.33	(6)	**24.34**	24.10	1
General and administrative expenses	**2.02**	3.44	(41)	**1.87**	2.33	(20)
Interest	**1.66**	2.45	(32)	**1.72**	1.96	(12)
CASH NETBACK	**22.89**	22.44	2	**20.75**	19.81	5
Unrealized loss on financial contracts	**2.99**	0.37	708	**0.36**	0.85	(58)
Stock-based compensation expense	**0.25**	0.22	13	**0.34**	0.25	34
Depletion, depreciation and accretion	**20.21**	21.29	(5)	**20.56**	23.63	(13)
Future income taxes reduction	**(0.81)**	(1.63)	(50)	**(0.22)**	(1.68)	(87)
NET EARNINGS (LOSS)	**0.25**	2.19	(89)	**(0.29)**	(3.23)	(91)

SELECTED INFORMATION

OVER THE PAST TWO YEARS, HOW HAS DELPHI PERFORMED AND WHAT SIGNIFICANT FACTORS CONTRIBUTED TO THE RESULTS?

Over the last eight quarters production has grown from 6,762 boe/d to 8,539 boe/d. Production for the last eight quarters reflects the following events. In the first six months of 2009, production growth was achieved with drilling success at Bigstone and Hythe, Alberta, primarily focused on natural gas opportunities. With crude oil and natural gas prices going in opposite directions through 2009, the capital program in the second half of 2009 was geared toward drilling for crude oil while acquiring strategic natural gas properties and infrastructure. The Company completed four natural gas property and infrastructure acquisitions in the Deep Basin of North West Alberta in the latter half of 2009. Continued drilling success in 2010 focused on light oil and liquids-rich natural gas opportunities has resulted in record fourth quarter and annual production of 8,539 boe/day and 8,086 boe/day, respectively. The 2010 average production represents growth of 19 percent over 2009.

Over the past two years, the changes in revenue and cash flow from quarter to quarter primarily reflect the increased production volumes achieved and the volatility of commodity prices.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices have been realized in the winter months, reflecting demand for heating with lower prices through the summer months as production is placed in storage for the upcoming heating season demand. In 2009, reduced heating and industrial demand due to the global economic crisis caused natural gas prices to decrease further as a result of concerns over excess supply relative to demand. The average spot price for AECO in 2009 was $3.96 per mcf, the lowest average price in ten years. The average spot price for AECO in 2010 increased only one percent to $4.00 per mcf.
Crude oil prices had recovered to over U.S. $80.00 per barrel by the end of 2009 from a low earlier in the year of U.S. $33.98 per barrel. In 2010, crude oil averaged U.S. $79.55 which was a 28 percent increase over the comparative period in 2009.

Net earnings of the Company are primarily driven by the difference between the cash flow netback realized per boe of production versus the Company's depletion, depreciation and amortization ("DD&A") rate of $20.56 per boe. The Company continues to reduce its DD&A rate by finding and developing reserves at a cost less than the average DD&A rate. Overall finding and development costs were $12.06 per proved boe in 2009 and $18.10 per proved boe in 2010.

The following table sets forth certain information of the Company for the past eight consecutive quarters outlining this performance.

	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31
	2010	*2010*	*2010*	*2010*	*2009*	*2009*	*2009*	*2009*
PRODUCTION								
Natural gas (mcf/d)	**38,918**	39,439	38,540	38,349	34,626	33,628	35,641	34,813
Oil (bbls/d)	**1,147**	831	1,074	745	630	624	371	475
Natural gas liquids (bbls/d)	**906**	710	538	508	487	544	498	485
Barrels of oil equivalent (boe/d)	**8,539**	8,114	8,035	7,645	6,888	6,773	6,809	6,762
FINANCIAL								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**30,475**	28,080	29,125	29,519	26,297	24,433	23,229	24,205
Funds from operations (cash flow)	**17,987**	15,120	12,988	15,157	14,218	12,635	12,371	10,017
Per share – basic	**0.16**	0.13	0.12	0.15	0.14	0.16	0.16	0.13
Per share – diluted	**0.16**	0.13	0.12	0.15	0.14	0.16	0.16	0.13
Net earnings (loss)	**204**	(1,566)	(2,742)	3,260	1,386	(3,278)	(2,817)	(3,320)
Per share – basic	-	(0.01)	(0.03)	0.03	0.02	(0.04)	(0.04)	(0.04)
Per share – diluted	-	(0.01)	(0.03)	0.03	0.02	(0.04)	(0.04)	(0.04)

ON AN ANNUAL BASIS, HOW HAS DELPHI PERFORMED?

The decrease in revenue and net earnings from 2008 to 2009 was primarily due to the significant drop in natural gas prices. The increase in revenue and net earnings from 2009 to 2010 was due to a combination of higher production volumes, higher liquids prices and lower production costs offset by a lower realized price for natural gas.

	2010	*2009*	*2008*
Revenue	**117,199**	98,164	135,402
Net earnings/(loss)	**(844)**	(8,029)	5,094
Total assets	**412,329**	361,698	364,538
Bank debt plus working capital	**108,054**	92,538	109,237

LIQUIDITY AND CAPITAL RESOURCES

SHARE CAPITAL

WHAT HAS BEEN THE MARKET ACTIVITY IN THE COMPANY'S COMMON SHARES?

At December 31, 2010, the Company had 112.8 million common shares outstanding (December 31, 2009 – 101.2 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and twelve months ended December 31, 2010.

	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2010
Weighted Average Common Shares		
Basic	**112,804**	107,934
Diluted	**115,238**	107,934
Trading Statistics (1)		
High	**2.47**	3.18
Low	**2.02**	1.70
Average daily volume.	**277,521**	465,615

(1) Trading statistics based on closing price.

HOW MANY COMMON SHARES AND STOCK OPTIONS ARE CURRENTLY OUTSTANDING?

As at March 15, 2011, the Company had 113.3 million common shares outstanding and 7.3 milllion stock options outstanding. The stock options have an average exercise price of $1.63 per share.

SOURCES AND USES OF FUNDS

	Three Months Ended December 31, 2010	Twelve Months Ended December 31, 2010
SOURCES:		
Funds from operations	**17,987**	61,252
Disposition of petroleum and natural gas properties	-	247
Acquisition of petroleum and natural gas properties	**369**	-
Issue of common shares	-	30,250
Exercise of stock options	**102**	775
	18,458	92,524
USES:		
Cash and cash equivalents	**4,154**	4,178
Capital expenditures	**18,314**	105,791
Acquisition of petroleum and natural gas properties	-	18
Share issue costs	-	1,966
Expenditures on site restoration and reclamation	**265**	265
Change in non-cash working capital	**20,725**	4,206
	43,458	116,424
Increase in bank debt	**25,000**	23,900

BANK DEBT PLUS WORKING CAPITAL DEFICIENCY (NET DEBT)

HOW MUCH BANK DEBT WAS OUTSTANDING ON DECEMBER 31, 2010?

At December 31, 2010, the Company had $80.0 million outstanding in the form of bankers' acceptances, $25 million drawn under Canadian-based prime loans and a working capital deficiency of $3.1 million for total net debt of $108.1 million excluding the financial asset of $2.1 million relating to the unrealized gain on financial commodity contracts and the associated future income tax liability.

WHAT ARE THE COMPANY'S CREDIT FACILITIES AND WHEN IS THE NEXT SCHEDULED REVIEW OF THE BORROWING BASE?

The Company has a revolving credit facility of $140.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2011, the term-out date. The term-out date may be extended for a further 364 day period upon approval by the banks. Following the term-out date, the facilities would be available on a non-revolving basis for a one year term. The credit facility bears interest based on a sliding scale pricing grid tied to the Company's trailing debt to cash flow ratio: from a minimum of the bank's prime rate plus 1.75 percent to a maximum of the bank's prime rate plus 4.75 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.75 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.75 percent.

CONTRACTUAL OBLIGATIONS

DOES THE COMPANY HAVE ANY CONTRACTUAL OBLIGATIONS AS OF DECEMBER 31, 2010 THAT WILL REQUIRE FUNDING IN FUTURE YEARS?

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. The Company also has a lease for office space in Calgary, Alberta.

The future minimum commitments over the next five years are as follows:

	2011	2012	2013	2014	2015
Gathering, processing and transmission	4,280	3,870	3,072	2,958	2,958
Office and equipment lease	1,612	775	390	-	-
Total	5,892	4,645	3,462	2,958	2,958

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

DOES DELPHI HAVE ANY OUTSTANDING GUARANTEES ON BEHALF OF THIRD PARTIES OR ANY OFF-BALANCE SHEET ARRANGEMENTS WHICH COULD LEAD TO LIABILITIES IN THE FUTURE?

Delphi has not entered into any guarantees or off-balance sheet arrangements. Certain lease agreements entered into in the normal course of operations could be considered off-balance sheet arrangements, however, all leases are operating leases with lease payments charged to operating expenses or general and administrative expenses on a monthly basis according to the lease.

CRITICAL ACCOUNTING ESTIMATES

IN PREPARING THE COMPANY'S FINANCIAL STATEMENTS, IS DELPHI REQUIRED TO MAKE ESTIMATES OR ASSUMPTIONS ABOUT FUTURE EVENTS?

Delphi's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management reviews its estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion and the ceiling test are based on estimates of crude oil and natural gas reserves;
- Revenues, operating expenses and royalties for which accruals have been recorded for actual revenues and costs which have been earned or incurred but have not yet been received;
- Capital expenditures on projects that are in progress;

- Fair value of derivative contracts; and
- Asset retirement obligations including estimates of future costs and the timing of the costs.

NEW ACCOUNTING STANDARDS

WERE THERE ANY NEW ACCOUNTING STANDARDS IN 2010 WHICH THE COMPANY HAS HAD TO ADOPT AND COMPLY WITH?

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On January 1, 2011 International Financial Reporting Standards ("IFRS") will become generally accepted accounting principles in Canada. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. The project to convert to IFRS is being managed by an in-house team of accounting professionals who have engaged in IFRS educational programs and continue to develop the Company's transition to IFRS. The Company's auditors have been and will continue to be involved throughout the process to ensure the Company's policies are in accordance with these new standards.

In July 2009, an amendment to IFRS 1 - First Time Adoption of International Reporting Standards was issued that applies to oil and gas assets. The amendment allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets on a pro rata basis using reserve volumes or reserve values as of that date. Delphi has elected to use this exemption. IFRS 1 also provides a number of other optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application which are:

Business combinations – IFRS 1 would allow the Company to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations.

Share-based payments – IFRS 1 allows the Company an exemption on IFRS 2, "Share-Based Payments" to equity instruments which vested before the Company's transition date to IFRS.

Delphi has elected to use these exemptions.

The transition from Canadian GAAP to IFRS is significant and may materially affect our reported financial position and results of operations. At this time, the Company has identified key differences that will impact the financial statements and the current status of those items:

- Exploration and Evaluation ("E&E") assets – On transition to IFRS Delphi will re-classify all E&E assets that are currently included in the Property, Plant and Equipment ("PP&E") balance on the consolidated balance sheet. This will consist of the book value of undeveloped land that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment at the transition date and when indicators of impairment exist. Delphi has currently determined its E&E asset balance to be approximately $0.3 million at January 1, 2010 and that there is no transitional impairment of the E&E assets.

- Property, plant and equipment – This includes oil and gas assets in the development and production phases. The Company will allocate the amount recognized under current Canadian GAAP as at January 1, 2010 using reserve values to a cash generating unit ("CGU").

- Impairment of PP&E assets – Under IFRS, impairment tests of PP&E must be performed at the CGU level as opposed to the entire PP&E balance which is required under current Canadian GAAP through the full cost ceiling test. Impairment calculations are required to be performed using fair values of the PP&E assets and Delphi anticipates using discounted proved plus probable reserve values for impairment tests of PP&E. Delphi anticipates the PP&E assets of one of its non-core CGU's will be impaired as at January 1, 2010 under IFRS, resulting in a decrease to total PP&E of $3.9 million and an offsetting charge to the opening retained earnings or deficit. This CGU was sold in the second quarter of 2010.

- Depletion expense – On transition to IFRS Delphi has the option to base the depletion calculation on either proved reserves or proved plus probable reserves. Delphi will use proved plus probable reserves.
- Share-based payments – The Company has determined the major difference from current Canadian GAAP that would impact the Company is estimating forfeiture rates in advance as opposed to recognizing the impact when the forfeiture occurs. Delphi does not anticipate the difference to be significant.
- Provisions – The major difference between the current Canadian standards and IFRS appears to be the discount rate used to measure the asset retirement obligation ("ARO"). Under the current Canadian standard a credit adjusted risk free rate is used, whereby IFRS allow the use of a risk free rate when the expected cash flows are risked. There was debate within the industry on the discount rate and whether there should be a risk component to it. Based on recent comments made by the standard setters and positions within the industry, Delphi believes a risk free rate is more appropriate. As a result, Delphi has measured its ARO liability on transition using a risk free rate of four percent resulting in an increase to the liability of approximately $6.2 million with an offsetting charge to the opening retained earnings or deficit.
- Share capital – On transition to IFRS Delphi will be required to account for the issuance of flow-through shares differently. Under the current Canadian standard the entire amount of the flow-through renouncement is removed from share capital, whereas under IFRS the portion of the renouncement related to the premium paid on the shares remains in share capital. This adjustment must be applied retrospectively to all past flow-through transactions, resulting in an increase to share capital of approximately $7.4 million with an offsetting charge to the opening retained earnings or deficit.

In addition to the accounting policy differences, the Company's transition to IFRS will impact the internal controls over financial reporting, the disclosure controls and procedures and information technology ("IT") systems as follows:

Internal controls over financial reporting – Based on the Company's accounting policies under IFRS Delphi has assessed whether additional controls or changes in procedures are required. Delphi does not consider these changes to be significant.

Disclosure controls and procedures – Throughout the transition process, Delphi will be assessing stakeholder's information requirements and will ensure that adequate and timely information is provided while ensuring the Company maintains its due process regarding information that is disclosed.

IT Systems – Delphi has assessed the readiness of its accounting software and has and continues to assess other system requirements that may be needed in order to perform ongoing calculations and analysis under IFRS. These changes are not considered to be significant.

Management continues to finalize its accounting policies and choices and is continuing with its due process in regards to information that is disclosed. As such, the Company is currently unable to quantify the full impact on the financial statements of adopting IFRS, however, the Company has disclosed certain expectations above based on information known to date. Due to anticipated changes to IFRS and International Accounting Standards prior to Delphi's adoption of IFRS, certain items may be subject to change based on new facts and circumstances that arise after the date of this MD&A.

CORPORATE GOVERNANCE

OVERVIEW

The shareholders' interests are a critical factor in the operations and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate policies and procedures. Delphi's Board of Directors consists of six independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's Management Information Circular and Annual Information Form for a listing of committees that oversee specific aspects of the Company's operating and financial strategy.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Company's President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective and provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified.

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes made to the disclosure controls and procedures or internal controls over financial reporting during the fourth quarter.

ADDITIONAL INFORMATION

WHERE IS ADDITIONAL INFORMATION ABOUT DELPHI AVAILABLE?

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com, at the Company's website at www.delphienergy.ca or by contacting the Company at Delphi Energy Corp. Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or by e-mail at info@delphienergy.ca.

Fig. 6 – Management's Report

Management's Report

The financial statements of Delphi Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management. External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management members, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the financial statements.

DAVID J. REID
President and Chief Executive Officer

BRIAN P. KOHLHAMMER
Vice President Finance and Chief Financial Officer

Calgary, Canada
March 15, 2011

Fig. 7 – Auditors' Report

Independent Auditors' Report

TO THE SHAREHOLDERS OF DELPHI ENERGY CORP.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Delphi Energy Corp. ("the Company"), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of operations, comprehensive loss and retained earnings (deficit) and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2010 and 2009, and the results of its consolidated operations and its consolidated cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 15, 2011

Fig. 8 – Consolidated Financial Statements

Consolidated Balance Sheets

AS AT DECEMBER 31

(Stated in thousands of dollars)	**2010**	*2009*
ASSETS		
Current assets		
Cash	**4,039**	-
Accounts receivable	**17,897**	15,630
Prepaid expenses and deposits	**3,426**	6,004
Risk management asset (Note 10)	**2,080**	-
Future income taxes (Note 9)	**-**	112
	27,442	21,746
Property, plant and equipment (Note 5)	**384,887**	339,952
Total assets	**412,329**	361,698
LIABILITIES		
Current liabilities		
Outstanding cheques	**-**	139
Accounts payable and accrued liabilities	**28,416**	32,933
Risk management liability (Note 10)	**-**	381
Future income taxes (Note 9)	**551**	-
	28,967	33,453
Long term debt (Note 6)	**105,000**	81,100
Future income taxes (Note 9)	**23,860**	23,917
Asset retirement obligations (Note 7)	**10,984**	11,818
Risk management liability (Note 10)	**3,527**	-
	172,338	150,288
SHAREHOLDERS' EQUITY		
Share capital (Note 8)	**228,440**	200,055
Contributed surplus (Note 8)	**12,088**	11,048
Retained earnings (deficit)	**(537)**	307
Total shareholders' equity	**239,991**	211,410
Total liabilities and shareholders' equity	**412,329**	361,698

Commitments (Note 11)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

STEPHEN MULHERIN
Director

LAMONT C. TOLLEY
Director

Consolidated Statements of Operations, Comprehensive Loss and Retained Earnings (Deficit)

YEARS ENDED DECEMBER 31

(Stated in thousands of dollars, except per share amounts)	2010	2009
REVENUE		
Petroleum and natural gas sales	113,772	94,618
Realized gain on risk management activities (Note 10)	3,427	3,546
	117,199	98,164
Royalties	(14,420)	(8,982)
Unrealized loss on risk management activities (Note 10)	(1,066)	(2,102)
	101,713	87,080
EXPENSES		
Operating	22,013	22,551
Transportation	8,908	6,739
General and administrative	5,531	5,788
Stock-based compensation (Note 8)	990	615
Interest	5,075	4,863
Depletion, depreciation and accretion	60,687	58,724
	103,204	99,280
Loss before income taxes	(1,491)	(12,200)
TAXES (Note 9)		
Future income taxes (reduction)	(647)	(4,171)
	(647)	(4,171)
Net loss and comprehensive loss	(844)	(8,029)
Retained earnings, beginning of the year	307	8,336
Retained earnings (deficit), end of the year	(537)	307
Loss per share (Note 8)		
Basic and diluted	(0.01)	(0.10)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

YEARS ENDED DECEMBER 31

(Stated in thousands of dollars)	2010	2009
CASH FLOW FROM (USED IN) OPERATING ACTIVITIES		
Net loss	**(844)**	(8,029)
Add non-cash items:		
Depletion, depreciation and accretion	**60,687**	58,724
Stock-based compensation	**990**	615
Unrealized loss on risk management activities	**1,066**	2,102
Future income taxes (reduction)	**(647)**	(4,171)
Expenditures on asset retirement obligations	**(265)**	(167)
Change in non-cash working capital (Note 12)	**(2,154)**	(4,142)
	58,833	44,932
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Issue of common shares, net of issue costs	**28,284**	14,977
Issue of flow-through common shares	-	6,360
Exercise of stock options	**775**	43
Repayment of acquired debt (Note 4)	-	(6,750)
Increase (decrease) in long term debt	**23,900**	(10,300)
	52,959	4,330
CASH FLOW AVAILABLE FOR INVESTING ACTIVITIES	**111,792**	49,262
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Capital expenditures	**(105,791)**	(33,946)
Disposition of petroleum and natural gas properties	**247**	20,718
Acquisition of petroleum and natural gas properties	**(18)**	(30,873)
Corporate acquisition costs (Note 4)	-	(869)
Change in non-cash working capital (Note 12)	**(2,052)**	(5,355)
	(107,614)	(50,325)
Increase (decrease) in cash and cash equivalents	**4,178**	(1,063)
Cash and cash equivalents, beginning of the year	**(139)**	924
Cash and cash equivalents, end of the year	**4,039**	(139)
Cash and cash equivalents is comprised of:		
Cash	**4,039**	-
Outstanding cheques	-	(139)
	4,039	(139)
Interest paid	**5,003**	5,099

See accompanying notes to the consolidated financial statements.

Fig. 9 - Notes to the Consolidated Financial Statements

Notes to the Consolidated Financial Statements

AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

(ALL TABULAR AMOUNTS ARE STATED IN THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. ("the Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a publicly-traded company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in North West Alberta.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results may differ from these estimates.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company, its wholly owned subsidiary and a partnership. All inter-entity transactions and balances have been eliminated.

(B) PETROLEUM AND NATURAL GAS OPERATIONS

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and the costs of production equipment.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20 percent or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted using the unit-of-production method based upon total proved reserves before royalties as determined by the Company's independent reserves engineers. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from the depletion calculation. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying amount of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying amount of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is assessed to not be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk-free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20 percent to 50 percent.

(C) JOINT OPERATIONS

Certain of the Company's exploration, development and production activities are conducted jointly with others and accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(D) GOODWILL

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of the net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and is charged to earnings in the period of the impairment.

(E) ASSET RETIREMENT OBLIGATIONS

The Company records the future cost associated with removal, site restoration and asset retirement costs of property, plant and equipment. The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the Company's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of property, plant and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded. The associated asset retirement cost included in property, plant and equipment is amortized to earnings using the unit-of-production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(F) STOCK-BASED COMPENSATION

The Company records a compensation cost for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation cost is a charge to earnings or is capitalized as a cost of exploration and development activities with an offsetting increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as an increase to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(G) FUTURE INCOME TAXES

The Company follows the asset and liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(H) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(I) PER SHARE AMOUNTS

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock-based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(J) FINANCIAL INSTRUMENTS

i) Financial instruments – recognition and measurement

Financial instruments are classified into one of the following five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives and non-financial derivatives are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost determined using the effective interest rate method. The accounting for subsequent changes in fair value depends on initial classification, as follows: changes in fair value of held-for-trading financial assets are recognized in net earnings and changes in fair value of available-for-sale financial instruments are recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts are recorded in net earnings.

The Company classifies its cash as held-for-trading which is measured at fair value. Risk management asset/liability is classified as held-for-trading and is measured at fair value. Accounts receivable are classified as loans and receivables and are measured at amortized cost. Accounts payable and long term debt are classified as other financial liabilities and are measured at amortized cost.

ii) Derivatives

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless exempt from derivative accounting treatment if the normal purchase and sale election is made at the time the Company entered into the contract. All changes in the fair value of derivative instruments are recorded in earnings unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income. The Company has a risk management program whereby the commodity price associated with a portion of its future production is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company sells forward a portion of its future production by entering into a combination of fixed price physical sale contracts with customers and fixed price financial contracts with financial counterparties. The Company has elected not to use hedge accounting on its fixed price contracts with financial counterparties resulting in all changes in fair value being recorded in the statement of earnings. The Company has elected to account for its physical commodity sales contracts which were entered into and continue to be held for the purpose of delivery of production in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives. Physical commodity sale contracts based in United States dollars include an embedded derivative associated with the foreign exchange rate. Due to this embedded derivative, the changes in the fair value of these contracts are included in the statement of earnings.

iii) Other comprehensive income

The Company includes a statement of comprehensive income, which is comprised of net earnings and other comprehensive income which, for the Company, relates to changes in gains or losses on derivatives designated as cash flow hedges. The Company has combined this statement with the statement of earnings.

iv) Transaction costs

Transaction costs attributable to financial instruments classified as other than held-for-trading are included in the recognized amount of the related financial instrument and recognized over the term of the resulting financial instrument using the effective interest rate method.

(K) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The ceiling test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon future costs, expected inflation rates and other assumptions. The amounts for stock-based compensation are based on estimates of risk-free interest rates, expected lives and volatility. The fair value estimates for derivatives are based on expected future natural gas prices and volatility in those prices. Future income taxes are based on estimates as to timing of the reversal of temporary differences at tax rates substantively enacted in those years. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(L) CASH AND CASH EQUIVALENTS

The Company considers deposits in banks less outstanding cheques as cash and cash equivalents.

(M) REVENUE RECOGNITION

Petroleum and natural gas sales are recognized in earnings when the title and risks pass from the Company to its customer.

NOTE 3: NEW ACCOUNTING STANDARDS

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian generally accepted accounting principles ("GAAP") for years beginning on or after January 1, 2011. Thus, effective January 1, 2011, the Company will be required to prepare its consolidated financial statements in accordance with IFRS, with appropriate comparative figures for the year ended December 31, 2010.

NOTE 4: CORPORATE ACQUISITION

During the fourth quarter of 2009, the Company acquired all of the issued and outstanding shares of Fairmount Energy Inc. ("Fairmount"), a publicly-traded company involved in the exploration for, development and production of crude oil and natural gas primarily in North West Alberta, for share consideration of 0.3571 of a share of the Company for each share of Fairmount. The aggregate purchase price of $6.4 million was paid for by issuing 5,834,974 common shares of the Company. The common shares issued by the Company were valued at $1.09 per share, representing the weighted average closing price of the Company's shares around the date of announcing the acquisition. The transaction was accounted for using the purchase method. The consolidated accounts of the Company include the results of Fairmount since October 8, 2009, the date the Company acquired control of Fairmount.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition.

PURCHASE PRICE:	
Share consideration	*6,360*
Corporate acquisition costs	*869*
	7,229
ALLOCATED:	
Petroleum and natural gas properties	*7,112*
Future income tax asset	*9,179*
Working capital	*(2,035)*
Bank debt	*(6,750)*
Asset retirement obligation	*(277)*
	7,229

NOTE 5: PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2010	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas properties	**532,308**	**270,294**	**262,014**
Production equipment	**164,741**	**42,359**	**122,382**
Furniture, fixtures and office equipment	**1,326**	**835**	**491**
	698,375	**313,488**	**384,887**

As at December 31, 2009	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	448,619	218,505	230,114
Production equipment	143,813	34,547	109,266
Furniture, fixtures and office equipment	1,277	705	572
	593,709	253,757	339,952

For the year ended December 31, 2010, the Company capitalized $4.5 million (December 31, 2009 - $4.2 million) of general and administrative costs directly related to exploration and development activities.

As at December 31, 2010, costs in the amount of $8.3 million (December 31, 2009 - $4.2 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $84.0 million (December 31, 2009 - $51.3 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves.

The Company performed a ceiling test calculation at December 31, 2010 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the ceiling test were based on the December 31, 2010 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the ceiling test.

	Natural Gas			Crude Oil			
	Henry Hub (US$/mmbtu)	AECO Spot (CDN$/mmbtu)	Delphi Gas (CDN$/mcf)	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	Bow River Hardisty (CDN$/bbl)	Delphi Oil (CDN$/bbl)
2011	*4.50*	*4.16*	*3.98*	*88.00*	*86.22*	*75.87*	*83.34*
2012	*5.15*	*4.74*	*4.60*	*89.00*	*89.29*	*75.89*	*87.21*
2013	*5.75*	*5.31*	*5.19*	*90.00*	*90.92*	*75.10*	*88.98*
2014	*6.25*	*5.77*	*5.69*	*92.00*	*92.96*	*76.23*	*90.90*
2015	*6.75*	*6.22*	*6.20*	*95.17*	*96.19*	*78.88*	*94.04*
2016	*7.10*	*6.53*	*6.54*	*97.55*	*98.62*	*80.87*	*96.41*
2017	*7.32*	*6.76*	*6.79*	*100.26*	*101.39*	*83.14*	*99.15*
2018	*7.47*	*6.90*	*6.95*	*102.74*	*103.92*	*85.21*	*101.63*
2019	*7.62*	*7.06*	*7.12*	*105.45*	*106.68*	*87.48*	*104.38*
2020	*7.77*	*7.21*	*7.28*	*107.56*	*108.84*	*89.25*	*106.48*
Thereafter (1)	*+2%/yr*	*+2%/yr*		*+2%/yr*	*+2%/yr*	*+2%/yr*	

(1) Percentage change of 2% represents the change in future prices each year after 2020 to the end of the reserve life.

NOTE 6: LONG TERM DEBT

	December 31, 2010	December 31, 2009
Prime-based loans	25,000	1,100
Bankers' acceptances	80,000	80,000
TOTAL DEBT	105,000	81,100

The Company has a revolving facility for $140.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2011, the term-out date. The term-out date may be extended for a further 364 day period upon approval by the banks. Following the term-out date, the facilities would be available on a non-revolving basis for a one year term. The credit facility bears interest based on a sliding scale pricing grid tied to the Company's trailing debt to cash flow ratio: from a minimum of the bank's prime rate plus 1.75 percent to a maximum of the bank's prime rate plus 4.75 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.75 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.75 percent.

The bankers' acceptances have terms ranging from 90 to 182 days and a weighted average effective interest rate of 4.24 percent over the term.

The facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to 20 years, is approximately $22.7 million (December 31, 2009 - $25.1 million). A credit-adjusted risk-free rate of 8.0 to 10.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

As at December 31	2010	2009
BALANCE, BEGINNING OF THE YEAR	11,818	9,730
Liabilities incurred	385	132
Liabilities disposed	(1,910)	(487)
Liabilities acquired	-	1,793
Liabilities settled	(265)	(167)
Accretion expense	956	817
BALANCE, END OF THE YEAR	10,984	11,818

NOTE 8: SHARE CAPITAL

(A) AUTHORIZED

An unlimited number of common shares.
An unlimited number of preferred shares issuable in series.

(B) COMMON SHARES ISSUED

As at December 31	2010 Outstanding shares (000's)	2010 Amount	2009 Outstanding shares (000's)	2009 Amount
BALANCE, BEGINNING OF THE YEAR	**101,166**	**200,055**	79,067	174,995
Issue of common shares	**11,000**	**30,250**	13,200	16,500
Issue of common shares - Fairmount (Note 4)	-	-	5,835	6,360
Issue of flow-through common shares	-	-	3,000	6,360
Exercise of stock options	**659**	**775**	64	43
Allocated from contributed surplus	-	**418**	-	23
Share issue costs	-	**(1,966)**	-	(1,523)
Future tax effect of share issue costs	-	**523**	-	405
Tax benefit renounced to shareholders	-	**(1,615)**	-	(3,108)
BALANCE, END OF THE YEAR	**112,825**	**228,440**	101,166	200,055

On September 30, 2009, the Company issued 13.2 million common shares at a price of $1.25 per share for gross proceeds of $16.5 million.

On November 16, 2009, the Company issued 3.0 million flow-through common shares at a price of $2.12 per share for gross proceeds of $6.4 million.

On June 3, 2010, the Company issued 11.0 million common shares at a price of $2.75 per share for gross proceeds of $30.3 million.

As at December 31, 2010, the Company has incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through common shares issued in 2009. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by Canada Revenue Agency.

(C) STOCK OPTIONS

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options up to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry. Options granted prior to September 1, 2009 vested over a two-year period starting on the date of grant. Options granted on September 1, 2009 or later vest over a two-year period with one-third vesting six months after the date of grant and one-third on each of the first and second anniversary of the grant date. The exercise price of each option equals the five day weighted average of the market price of the Company's common shares, immediately preceding the date of the grant. As at December 31, 2010 there were 7.8 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

	2010		*2009*	
As at December 31	**Outstanding options (000's)**	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
BALANCE, BEGINNING OF THE YEAR	***7,428***	***1.40***	*4,731*	*1.75*
Granted	***1,074***	***2.64***	*3,017*	*0.83*
Forfeited	***(67)***	***1.50***	*(256)*	*1.31*
Exercised	***(659)***	***1.18***	*(64)*	*0.67*
BALANCE, END OF THE YEAR	***7,776***	***1.59***	*7,428*	*1.40*
EXERCISABLE, END OF THE YEAR	***6,116***	***1.58***	*5,245*	*1.58*

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2010.

	Options outstanding			**Options exercisable**	
Range of exercise price	**Outstanding options (000's)**	**Weighted average exercise price**	**Weighted average remaining term (years)**	**Exercisable options (000's)**	**Weighted average exercise price**
$0.65 - $0.97	***1,804***	***0.66***	***3.16***	***1,165***	***0.66***
$0.98 - $1.54	***525***	***1.21***	***3.35***	***280***	***1.25***
$1.55 - $1.72	***3,736***	***1.67***	***1.91***	***3,711***	***1.67***
$1.73 - $2.15	***560***	***1.88***	***2.44***	***440***	***1.82***
$2.16 - $3.34	***1,151***	***2.81***	***3.97***	***520***	***2.91***
TOTAL	***7,776***	***1.59***	***2.64***	***6,116***	***1.58***

(D) STOCK-BASED COMPENSATION

The Company accounts for its stock-based compensation using the fair value method for all stock options. For the year ended December 31, 2010, Delphi recorded non-cash compensation expense of $1.0 million (December 31, 2009 - $0.6 million). The Company capitalized $0.5 million (December 31, 2009 - $0.9 million) of stock-based compensation directly related to exploration and development activities. The future income tax liability associated with the capitalized stock-based compensation in the amount of $0.2 million (December 31, 2009 - $0.3 million) has also been capitalized for the year.

During the year ended December 31, 2010, the Company granted 1.1 million options. The fair values of all options granted during the year are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the year was $1.51 per option (December 31, 2009 - $0.43 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

Years ended December 31	***2010***	*2009*
Risk-free interest rate (%)	***2.7***	*2.1*
Expected life (years)	***5.0***	*5.0*
Expected volatility (%)	***65.8***	*62.6*

(E) CONTRIBUTED SURPLUS

The following table outlines the changes in the contributed surplus balance.

As at December 31	2010	2009
BALANCE, BEGINNING OF THE YEAR	**11,048**	9,605
Stock-based compensation expensed	**990**	615
Stock-based compensation capitalized	**468**	851
Reclassification to common shares on exercise of stock options	**(418)**	(23)
BALANCE, END OF THE YEAR	**12,088**	11,048

(F) NET LOSS PER SHARE

Net loss per share has been based on the following weighted average common shares.

Years ended December 31	2010	2009
Basic	**107,934**	84,065
Diluted	**107,934**	84,065

(G) CAPITAL MANAGEMENT

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets, as the components of capital to be managed.

The Company's objective in managing its capital is to ensure adequate and appropriate sources of capital are available to execute a capital investment program while maintaining a flexible overall capital structure. Maintaining a flexible capital structure is important due to the inherent risks in oil and gas operations and the volatility of commodity prices.

The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas prices and the cost of oilfield services. Additionally, the Company establishes internal processes to monitor and estimate planned capital expenditures, forecast funds from operations and current and forecast debt levels.

The key measure used by the Company to evaluate its capital structure is the ratio of net debt to funds from operations, defined as cash flow from operating activities before expenditures on asset retirement obligations and change in non-cash working capital from operating activities. This ratio represents the time period required to repay the Company's net debt from funds generated from operations on the assumption there are no further capital expenditures incurred and funds from operations remain constant. The measure is often calculated on a historic annual basis and on an annualized most recent quarter basis to provide a more current view of the Company's capital structure.

At December 31, 2010 net debt, excluding risk management assets or liabilities and the associated future income taxes, was $108.1 million and funds from operations was $61.3 million resulting in a net debt to funds from operations ratio of 1.8:1. The Company is focused on achieving its internal target range for this ratio of approximately 1.5 times.

The Company maintains an active risk management program as an integral part of its capital management strategy to mitigate the volatility in funds from operations resulting from fluctuating commodity prices. The net debt to funds from operations ratio is the key driver in determining whether to maintain or alter the capital structure. To alter the capital structure of the Company, consideration is given to the level of credit available under current banking facilities, the proceeds on disposition of properties, the amount of the planned capital expenditure program and the offering of new common share equity if available on acceptable terms.

NOTE 9: TAXES

(A) EXPECTED INCOME TAX RATE

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial income tax rates to the Company's earnings before income taxes.

The difference relates to the following items:

Years ended December 31	2010	2009
Loss before income taxes	**(1,491)**	(12,200)
Statutory tax rate	**28.01%**	29.07%
Expected income tax expense (recovery)	**(418)**	(3,547)
Stock-based compensation	**277**	178
Reduction in future income tax rates	**(497)**	(771)
Other	**(9)**	(31)
Total income tax expense (recovery)	**(647)**	(4,171)

(B) FUTURE INCOME TAX LIABILITY

The income tax effect of temporary differences that give rise to significant portions of the future income tax assets and liabilities are presented below:

As at December 31	2010	2009
Future income tax assets:		
Asset retirement obligations	**2,812**	2,955
Attributed Canadian Royalty Income	**361**	362
Non capital losses	**4,097**	4,093
Share issue costs	**1,011**	998
Risk management liability	**934**	112
Future income tax liabilities:		
Risk management asset	**(551)**	-
Property, plant and equipment	**(33,075)**	(32,325)
Net future income tax liability	**(24,411)**	(23,805)

Non-capital losses of $16.4 million expire in the year 2028.

NOTE 10: FINANCIAL INSTRUMENTS

(A) RISK MANAGEMENT OVERVIEW

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Risk management is ultimately established by the Board of Directors and is implemented and monitored by senior management. The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in funds from operations resulting from fluctuating commodity prices. The strategy is designed to take advantage of the upward swings in natural gas prices as a result of the changes in demand/supply fundamentals and/or the movement of significant financial assets invested in the natural gas market as a pure commodity investment.

(B) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The Company's financial instruments recognized on the balance sheet include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, long-term debt and the risk management asset or liability. The fair value of financial assets and liabilities that are included on the balance sheet, other than the risk management asset or liability, approximate their carrying amounts due to long-term debt being at a floating interest rate and all other financial assets and liabilities having a short term maturity.

The Company's financial derivative contracts are transacted in active markets. The contracts are measured at fair values that are classified as Level 2 in accordance with the following hierarchy.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

(C) MARKET RISK

Market risk is comprised of foreign currency exchange rate risk, interest rate risk and commodity price risk. The Company utilizes both financial derivatives and physical delivery contracts to manage market risks.

FOREIGN CURRENCY EXCHANGE RATE RISK

Foreign currency exchange rate risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are affected by changes in the exchange rate between the Canadian and United States dollar. The exchange rate could affect the values of certain contracts, however, this indirect influence cannot be accurately quantified. The Company had no foreign exchange rate swap or related financial contracts in place as at December 31, 2010.

INTEREST RATE RISK

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

Interest rate risk is partially mitigated through short-term fixed rate borrowings using bankers' acceptances.

The Company has also entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $40.0 million maturing on May 4, 2011. The bankers' acceptance rate on the transaction has an average fixed rate over two years of 0.94 percent. The effective interest rate over the two year term on $40.0 million of bankers' acceptances will be 0.94 percent plus the applicable stamping fee according to the pricing grid for bankers' acceptances. The fair value of this contract at December 31, 2010 is a loss of $21,000. If interest rates on prime-based loans had been 100 basis points lower with all other variables held constant, net earnings for the year ended December 31, 2010 would have been higher by $0.1 million (December 31, 2009 - $0.2 million).

COMMODITY PRICE RISK

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are affected not only by the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. The Company has a commodity price risk management program in place whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production by entering into a combination of fixed price physical sale contracts with customers and financial commodity contracts. The Company's policy is to enter into commodity contracts to a maximum of 40 – 50 percent of current production volumes.

As at December 31, 2010, the Company had the following financial derivative contracts which were recorded at fair value on the balance sheet as a current asset of $2.1 million and long-term liability of $3.5 million (December 31, 2009 - current liability of $0.4 million) with changes in fair value included in unrealized gain (loss) on risk management activities in the statement of earnings. For the year ended December 31, 2010, the financial contracts resulted in gains of $3.4 million (December 31, 2009 - $3.5 million) that have been included in the statement of earnings as a realized gain on risk management activities.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2010 – March 2011	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$5.72 fixed*
January 2011 – December 2011*	*Natural Gas*	*Financial*	*2,500 GJ/d*	*$7.14 Call*
January 2011 – December 2011***	*Natural Gas*	*Financial*	*3,000 GJ/d*	*$4.00 Put*
January 2011 – December 2012**	*Crude Oil*	*Financial*	*600 bbls/d*	*U.S. $90.00 Call*
April 2011 – December 2011**	*Natural Gas*	*Financial*	*6,810 GJ/d*	*$5.69 fixed*
January 2012 – December 2012***	*Natural Gas*	*Financial*	*3,000 GJ/d*	*$4.50 Call*

* *The Company sold a natural gas call contract at $7.14 per gigajoule on 2,500 gigajoules per day for the period January 1, 2011 through December 31, 2011. This call was sold to acquire a natural gas put on 2,500 gigajoules per day at a price of $4.75 per gigajoule for the period April 1, 2010 through October 31, 2010.*

** *The Company has acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. This contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012.*

*** *The Company has acquired a natural gas put contract at $4.00 per gigajoule on 3,000 gigajoules per day for the period January 1, 2011 through December 31, 2011. This put was paid for with the sale of a natural gas call on 3,000 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.*

The Company has Canadian dollar physical sales contracts. The Canadian dollar physical sales contracts were entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts and have not been recorded at fair value. As at December 31, 2010, the Company had the following physical sales contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2010 – March 2011	*Natural Gas*	*Physical*	*1,500 GJ/d*	*$5.74 fixed*
April 2010 – March 2011	*Natural Gas*	*Physical*	*3,000 GJ/d*	*$6.12 fixed*
April 2010 – March 2011	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$5.73 fixed*
January 2011 – December 2011	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$3.79 fixed*
January 2011 – December 2011****	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$4.12 fixed*
April 2011 – October 2011	*Natural Gas*	*Physical*	*2,000 GJ/d*	*$5.66 fixed*
January 2012 – December 2012****	*Natural Gas*	*Physical*	*2,500 GJ/d*	*$4.50 Call*

**** *The Company has acquired a natural gas contract at $4.12 per gigajoule on 2,500 gigajoules per day for the period January 1, 2011 through December 31, 2011. This contract was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.*

For the year ended December 31, 2010, the Canadian dollar physical contracts resulted in settlement gains of \$12.7 million (December 31, 2009 - \$19.2 million) that have been included in petroleum and natural gas sales. As at December 31, 2010, if natural gas prices had been higher by \$0.10 per mcf, with all other variables held constant, the net change in the unrealized gain on risk management activities in the statement of earnings for the year would have been lower by approximately \$0.4 million (December 31, 2009 – \$0.4 million).

(D) CREDIT RISK

Credit risk represents the financial loss to the Company if counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners. All of the Company's accounts receivable are with customers and joint interest partners in the oil and gas industry and are subject to normal industry credit risks. With respect to counterparties to financial commodity contracts, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company attempts to mitigate the risk related to joint interest receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, partners are exposed to various industry and market risks that could result in non-collection. The Company does not typically obtain collateral from natural gas marketers or joint interest partners; however, the Company does have the ability to request pre-payment of certain major capital expenditures and withhold production from joint interest partners in the event of non-payment of amounts owing.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. The Company does not consider an allowance for doubtful accounts is required as at December 31, 2010, however, bad debt expense of \$0.3 million was recorded during the year primarily related to the settlement of disputed processing fees with a joint venture partner.

As at December 31, 2010 the Company's aged receivables are as follows.

Current (less than 30 days)	***15,006***
Past due (31-90 days)	***1,598***
Past due (more than 90 days)	***1,293***
TOTAL	***17,897***

(E) LIQUIDITY RISK

The Company requires sufficient cash to fund its operating costs and capital program that are designed to maintain or increase production and develop reserves, to acquire petroleum and natural gas assets and to satisfy debt obligations. The majority of capital spent will be funded through cash flow from operating activities. The Company enters into risk management contracts designed to improve risk-adjusted returns and to ensure adequate cash flow to fund the Company's capital program and maintain liquidity. The Company uses a combination of both financial and physical commodity price contracts. Contracts are initiated within the guidelines of the Company's risk management program and are not entered into for speculative purposes. The Company also has a 364 day revolving credit facility with a syndicate of Canadian chartered banks with a one year term-out provision.

The following are the contractual maturities of financial liabilities as at December 31, 2010.

FINANCIAL LIABILITIES	< 1 Year	1 – 2 Years	3 – 5 Years	Thereafter
Accounts payable and accrued liabilities	28,416	-	-	-
Risk management liability		3,527	-	-
Long term debt – principal	-	105,000	-	-
Total	28,416	108,527	-	-

NOTE 11: COMMITMENTS

The Company is committed to future minimum payments for natural gas transmission and processing, operating leases on compression equipment and office space. Payments required under these commitments for each of the next five years are: 2011 - $5.9 million; 2012 - $4.6 million; 2013 - $3.5 million; 2014 - $3.0 million; 2015 - $3.0 million.

NOTE 12: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

Years ended December 31	**2010**	2009
Change in working capital item:		
Accounts receivable	**(2,267)**	(550)
Prepaid expenses and deposits	**2,578**	(2,874)
Accounts payable and accrued liabilities	**(4,517)**	(6,073)
Total change in non-cash working capital	**(4,206)**	(9,497)
Relating to:		
Operating activities	**(2,154)**	(4,142)
Investing activities	**(2,052)**	(5,355)
	(4,206)	(9,497)

Fig. 10 - Corporate Information

Corporate Information

DIRECTORS

DAVID J. REID
President and Chief Executive Officer
Delphi Energy Corp.

TONY ANGELIDIS
Senior Vice President Exploration
Delphi Energy Corp.

HARRY S. CAMPBELL, Q.C. (3)
Partner
Burnet, Duckworth & Palmer LLP

ROBERT A. LEHODEY, Q.C. (2) (3)
Partner
Osler, Hoskin & Harcourt LLP

STEPHEN MULHERIN (1)
Partner
Polar Capital Corporation

ANDREW E. OSIS (1)(3)
Chief Executive Officer and Director
Poynt Corporation

DAVID SANDMEYER (2)
Director
Freehold Royalty Trust

LAMONT C. TOLLEY (1) (2)
Independent Businessman

(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Corporate Governance and Compensation Committee

AUDITORS

KPMG LLP

LEGAL COUNSEL

Osler, Hoskin & Harcourt LLP

TRANSFER AGENT

Olympia Trust Company

OFFICERS

DAVID J. REID
President and Chief Executive Officer

TONY ANGELIDIS
Senior Vice President Exploration

HUGO H. BATTEKE
Vice President Operations

MICHAEL K. GALVIN
Vice President Land

ROD A. HUME
Vice President Engineering

MICHAEL S. KALUZA
Chief Operating Officer

BRIAN P. KOHLHAMMER
Vice President Finance and Chief Financial Officer

CORPORATE OFFICE

300, 500 – 4th Avenue S.W.
Calgary, Alberta, T2P 2V6
Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

BANKERS

National Bank of Canada
The Bank of Nova Scotia
Alberta Treasury Branches

INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
mbbls	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf:1 bbl)
boe/d	barrels of oil equivalent per day
mmboe	million barrels of oil equivalent

Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

designed and produced by nonfiction studios inc.

DELPHI ENERGY CORP.
300, 500 – 4th Avenue S.W.
Calgary, Alberta, T2P 2V6

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

FSC
Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
Cert no. SW-COC-001858
www.fsc.org